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FEDERAL ENERGY REGULATORY COMMISSION

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REACTIVE POWER SUPPLY AND :

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The above-entitled matter came on for technical conference, pursuant to notice, at 9:10 a.m., Richard O'Neill, presiding.

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PANEL ONE, RELIABILITY AND TECHNICAL ISSUES

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MICHAEL CONNOLLY, CENTERPOINT ENERGY
RONALD SNEAD, CINERGY SERVICES (MISO TRANSMISSION OWNERS)
ANJAN BOSE, WASHINGTON STATE UNIVERSTY
ROBERT O'CONNELL, WILIAMS POWER COMPANY, INC.
JOHN HOWE, AMERICAN SEMICONDUCTOR
ERIC JOHN, ABB INC.

PANEL TWO, SHORT TERM REACTIVE POWER ISSUES

DENNIS BEHTEL, AMERICAN ELECTRIC POWER
ALLEN MOSHER, AMERICAN PUBLIC POWER ASSOCIATION
DAVID BERTAGNOLLI, ISO NEW ENGLAND
STEVEN WOFFORD, CONSTELLATION ENERGY COMMODIES GROUP, INC.
JOHN LUCAS, SOUTHERN COMPANY
JOHN SIMPSON, RELIANT ENERGY INC.
SCOTT HELYER, TENASKA, INC.

PANEL THREE, PROSPECTIVE REACTIVE POWER SOLUTIONS

FERNANDO ALVARDO, IEEE-USA ENERGY POLICY COMMITTEE
MICHAEL CALVIOU, NATIONAL GRID USA
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P R O C E E D I N G S

MR. O'NEILL: Good morning and thank you for coming to today's Reactive Power Conference. One of the objectives today is to get reactive power out of the attic and into the light. Unfortunately, reactive power suffers as a victim of mathematics. Mathematicians have a tendency to maze the numbers that they use. For example, they have numbers called rational and irrational, but they don't mean anything like what the normal use of the terms are. And for complex numbers they use real and imaginary. And reactive power has the unfortunate problem of being the imaginary part of a complex number, and sometimes people don't take it seriously.

Here today, hopefully, we can take it more seriously and try to better understand the role that reactive power plays in the electric power system. In particular, how it can contribute to reliability. How it can stimulate investment in reactive power to contribute to both reliability and efficient operation of the system. And to better formulate reactive power policy here at the Commission.

We have three sessions today. The first session is to deal with reliability technical issues, followed by issues of both short term and longer term policy making.

Even though I'm allotted fifteen minutes, I think I'm going to cut it short, kind of set a precedent here. And ask the speakers to limit their formal comments to five minutes so that we can have an active and reactive discussion. And with that, I think we will move on to the order of the published agenda. And we will start with Don Benjamin from NERC.

MR. BENJAMIN: Thank you, Mr. O'Neill, very much. And good morning to everybody. And thanks for holding the conference this morning. Thanks for being patient. Excuse me.

Reactive power supports the electromagnetic fields that makes AC Electric Power System possible. I guess if Tom Edison had his way all those years ago and we had a DC system, we wouldn't be sitting around the table here today.

Reactive power supplies the electromagnetic fields that are used for motor load, which is a good part of the load that is in US and Canada, as well as magnetic devices, electromagnetic devices like florescent lights that we have here around the building, and microphones, and power supplies that are in these neat TV screens around the room here.

When I read the Reactive Power Supply and

Consumption book, I thought this was a very good book that the Commission had put together. And I really applaud you for that very much. Whenever I read anything about reactive power, I always know that it's an authoritative source when there is the "head of the beer" analogy.

(Laughter)

MR. BENJAMIN: And so it too a few pages to get into that, but there on page eighteen it talks about the head on a glass of beer. Now, there are several solutions in dealing with that. One, you can get a bigger glass. The other thing is, you can dribble the beer along the side of the glass, and that prevents the head from forming. Or the third is, you can do what I do, and that is, drink Pepsi.

But we can't build bigger transmission lines. And reactive power is certainly a more serious issue than the head on a beer. I'd like to make three points on this, please.

First, reactive power does not travel far. You can't dispatch reactive power to just wherever you want to on the electric power system. So, there are many electrical and physical requirements that determine where you locate reactive resources, and how they are used.

The second point, static and dynamic reactive sources, and there's a lot of discussion about that in the book. And just very briefly, the most common static source of reactive power that we can think of are: things like capacitors, and inductors in the transmission line. And their static because they do anything, they just sit there. And dynamic reactive resources, such as, generators and synchronous condensers; they have very different characteristics. They are both very, very important in the electric transmission system to the operation of the system, but they are not substitutes for each other. And while they both play important roles, where they are installed and how they are used it very, very important.

Third, NERC doesn't get into market rules. But I would say this: whatever market rules the Commission may consider; those market rules must do at least two things. Number one; help ensure that there is sufficient reactive reserves and the right reactive reserves in the right place. And Number two; that those market rules allow the system operators to deploy those reactive reserves in real-time to maintain system reliability. Very, very important points for NERC.

So, those are the three points that I wanted to make. The NERC planning and operating committees are working on the many questions that the Commission asked in this report. We appreciate that list of questions. That sort of helps focus our attention on the issues that we need to deal with. We plan to file comments in a few weeks on those. I guess, in early April.

And again, thank you very much.

MR. O'NEILL: Thank you. Phil Fedora.

MR. FEDORA: Good morning everyone. Again, thank you for allowing me to speak today. My name is Phil Fedora and I'm the director of the market reliability interface activities for the Northeast Power Coordinating Council. NPCC is the International Electric Reasonable Reliability Council for the Northeastern and Eastern Canada. It includes New York state, six New England states, Ontario, Quebec, and the Maritime Provinces in Canada. It's a voluntary, non-profit organization. It's current membership is transmission providers and transmission customers that serve the Northeastern United States and Central and Eastern Canada.

Reactive power is certainly one of the aspects of buying reliable power over the electric system, that must be managed in a safe and effective manner. The consequences of not providing for its requirement are well documented in the Staff report. So, we need a way to understand and management its requirements.

So, what I want to do in my brief opening remarks is highlight some of the areas within NPCC that specifically deal with these issues; touch a little bit on what can be done to strengthen reliability compliance, absent enabling (inaudible) in the United States, and then respond to two of the questions that were raised in the Staff report.

More details of what I'm summarizing can be found in a handout that is being distributed with additional references to the documents and information that I'm going cite for those that would like to get further information.

The role of NPCC is to establish the processes that assure the reliable and efficient operation of the international, interconnected bulk power systems in Northeastern North America through the development and enforcement of regional specific criteria that are not inconsistent with NERC broad-based continent-wide reliability standards. NPCC coordinates system planning, design and operation, assesses reliability, and monitors and enforces mandatory compliance with its regional reliability criteria. And to the extent possible, facilitates the attainment of fair, effective and efficient competitive electric markets.

Our regionally-specific reliability criteria clearly establish design-based reliability objectives and accommodate market mechanisms, as appropriate, for achieving reliable operations.

The objective of NPCC's document A-2, which is the "Basic Criteria for Design and Operation of Interconnected Bulk Power Systems" is to ensure that the bulk power system is designed and operated to a level of reliability such that the loss of a major portion of the system, or unintentional separation of a major portion of the system will not result from any design contingencies. In NPCC the technique for ensuring reliability of bulk power system is to require that it be designed and operated to withstand representative, specified contingencies. Analyses of these simulations of these contingencies include assessments of the potential for widespread cascading outages due to overloads, instability or voltage collapse.

The criteria described in the NPCC Basic Criteria used in the design and operation of the power system. These criteria meet or exceed the NERC standards. And the criteria is applicable to all entities which are part or make use of the bulk power system.

NPCC conducts regional and interregional reliability analyses and facilitates broader regional planning efforts. The reason why operation security and area resource and transmission adequacy are assessed in order to maintain reliability.

NPCC Guideline B-3, "Guidelines for Inter-Area Voltage Control" provides general principles and guidance for effective inter-area voltage control consistent with the NPCC basic criteria. Specific methods to implement these guidelines may vary among areas, depending on local requirements. Coordinated inter-area voltage control is necessary to regulate voltages, protect equipment from damage, and prevent voltage collapse. Coordinate voltage regulation reduces electrical losses on the network and lessens equipment wear and tear.

Local control actions are generally most effective for voltage regulations. Occasions do arise when the adjacent areas can assist each other to compensate for deficiencies or excesses of reactive power, and improve voltage profiles and system security.

Each area develops and operates in accordance with its own voltage control requirements and procedures. These area requirements and procedures are consistent with the NPCC Criteria. Adjacent areas are familiar with each other's procedures and they usually agree upon procedures for inter-area voltage control.

NPCC reviews the reliability of the areas' planned bulk power system for conformance with its operating, planning and design criteria. The overall NPCC regional reliability and interregional security of the bulk power system is so assessed.

The other document that I want to mention is NPCC Document C-4, "Monitoring Procedures for Guidelines for Inter-Area Voltage Control" establishes monitoring procedures and performance review relative to the Inter-Area Voltage Control Guidelines.

As I said before, the NPCC members that obligates each member to plan design, and operate its bulk power system in compliance with the regionally specific liability criteria and broad-based continent-wide NERC standards. To assess and monitor compliance with the NERC and NPCC standards, reliability standards, NPCC has in place the Reliability Compliance and Enforcement Program. It was initially adopted in 2000, it establishes a mechanism to impose non-monetary sanctions for non-compliance to a specified set of reliability requirements.

The US-Canada Power System Outage Task Force Final Report on the Blackout of 2003 in recommendation number three addressed the need to strengthen the institutional framework for reliability management in North America. The Regional Managers Committee in its examination of the role of the Regional Reliability Council identified essential reliability functions and services, and required organizational principles for reliability assurance within the North American region.

To be noted that the RTOs alone cannot accomplish the task of assuring the reliability of the entire market due to the international character of the marketplace, and the desire for some parts of the country to refrain from implementing formal markets. An inclusive reliability structure is needed in order to permit Canadian and other entities to interact seamlessly with each other. Regional Reliability Councils, separate but complementary to the operating entities within its footprint, are most able to accomplish this objective.

The Regional Reliability Councils provide a significant means by which State and Provincial regulators can fulfill their political mandate to oversee the reliability of the electric system.

States, in the absence of enactment of US reliability legislation, and Provincial authorities could strengthen existing regulatory backstop for the enforcement of mandatory compliance with NERC standards and regional reliability council criteria for their jurisdictional electric utilities. NPCC supports the recent NARUC Resolution regarding the development of the model orders and legislation that could be considered by individual states to make NERC reliability standards and Regional Reliability Council's criteria mandatory.

I would just like to offer some comments briefly on two of the questions that were raised in the report on transmission reliability in the engineering section. The first one was, should there be interconnections standards with respect to merchant transmission?

In our February comments to the Generation Interconnection notebook we urged the Commission to consider broadening the scope of its rulemaking to include transmission projects, with inter-area impacts in the standardized interconnection procedures.

Simple accounting for transmission projects in the interconnection study base cases fails to guarantee the needed level of study coordination between proposed merchant transmission projects, and proposed generation interconnection project that is needed to maintain a reliable system.

In some cases merchant transmission projects posed a great potential for wide area impact and should be included in a standardized interconnection process. Regional Reliability Councils are uniquely situation to provide the study oversight needed to evaluate the wide area effects that some projects may have.

So, to combined two questions into one, can thermal or non-thermal transmission constraints be relieved by supplying or consuming reactive power? If so, how and to what extent? Well, yes.

As an example I've cited a reference to a study conducted by NPCC Regional Planning Forum. The objective was to explore innovative approaches to enhance the capabilities of the transmission grid from a wide are of trans-regional outlook.

The study affirmed that for both today's system and the future of 2006 system, the size of the largest NPCC single contingency the interconnection can reliably withstand is limited under 2000 megawatts, primarily due to lack of dynamic VAR support in response to the contingency on the New York system around its southern border with Pennsylvania.

The Regional Planning Forum screening analysis suggested that improvement of the New York post-contingency voltage response could allow for up to 800 megawatts of additional transfer capability from the existing Hydro-Quebec to NPCC interconnection. You could read further in the website reference simulations of the dynamic reactive compensation that was taken in the suggestion for the Oakdale, New Scotland, or Marcy New York processes.

The analysis of this represents a starting point. It's not meant to represent detailed planning analysis, proposal and endorsement of any particular project. There was no detail of cost-benefit analyses, nor extensive system or environmental studies undertaken.

However, the results did represent opportunities from a wide area trans-regional outlook to increase the existing capabilities of today's system that are also applicable to our future system.

I think that we'll all agree that increasing transfer capability at the time of system need enhances the overall reliability of that system.

Now, in closing what I would like to just mention, while reactive power of reliability needs should be assessed locally, regional differences and reliability practices address specific operational, and geographic characteristics of the electric infrastructure of a particular region.

NPCC criteria established the regional specific reliability requirements necessary to attain the security of this interconnected bulk power system. These criteria define the minimum requirements for both the design and operation of the Northeastern North America Electric Power System. While they are consistent with and meet NERC standards, they are more stringent. More stringent criteria and rules make for a more robust systems, especially when operating outside of the normal system conditions isn't common.

These requirements call for extra margin that adds flexibility when extra-ordinary events occur and reduces the likelihood of the need for load shedding in response to such system requirements.

MR. O'NEILL: Thank you. Mr. Connolly.

MR. CONNOLY: Good morning. Mike Connolly with CenterPoint Energy. I'm with the CenterPoint Energy Transmission Planning Group. I supervise the transmission planners. I've been with CenterPoint Energy for about 35 years now. And for the past 15 or 20 years I've been very closely involved with issues of reactive power, both from the planning and operation standpoint. And I've become quite familiar with the technical issues related to its production, deliver, and supply of reactive power.

CenterPoint Energy is an unbundled transmission distribution provider for most of the area in and around Houston, Texas. We serve around 16,000 megawatts of load. What we find is that subsequent to deregulation of the electric market in Texas, frequently we're in an operating position of importing significant amount of our power to serve our load. Previously, in the vertically integrated utility paradigm we generally operated with generation and load, pretty much equally in our area.

Now, we import up to about 30 percent of our generation to serve the load. The deregulation has displaced a significant amount of generation use in areas turned off. And as a result the dynamic reactive capability in Houston area is diminishing. So, we find ourselves in a situation where we feel like we are more susceptible to highline contingencies causing voltage collapse cascading out. This is possibly elements of both.

We've taken several measures to mitigate that situation. One is installation of an under voltage load shedding machine, which was a NERC recommendation subsequent to the 2003 Northeast blackout. That scheme is now complete and in service in our system.

We've increased installation of static reactive resources. We've installed several thousand MVARs of transmission conducted with (coughing, inaudible). And we've participated in efforts that led to the establishment of regional static reactive requirements for distribution load generators and transmission systems.

Generally, we find that the policies and ongoing efforts with regard to procurement of static reactive resources are basically going pretty well. We feel pretty comfortable through that aspect of things.

However, we do feel that the same cannot be said for dynamic reactive power and dynamic voltage stability issues. In particular, because the cost to remedy reliability concerns are much higher and the reliability standards are much less clear in dealing with the dynamic reactive stability issues.

So, we would like to focus comments on dynamic reactive power and voltage stability. We feel like that FERC has taken a significant first step in clarification of requirements regarding dynamic performance and the low voltage ride-through requirements for generators. It was part of the Wind numbers. In particular, we would like see the low voltage ride-through requirement extended to all generators. We think it is an appropriate type of requirement that would go a long ways towards ensuring the performance and stability of the power system under disturbance conditions.

We also feel that it would be appropriate that if you accept the notion of applying a ride-through requirement to the generators that the transmission system should also be required to provide some surgent performance. In other words, you would like the transmission system voltage to remain at a level that would avoid tripping the generators and leading to a cascading collapse. In that regards, in our handout, which I made available, we have a proposal for a transient voltage recovery criteria that would applied transmission systems. And that criteria would be applied specifically to transmission stations that serve generators, to ensure that you had coordination between the generator ride-through capability and the performance of the transmission grid.

The third area that I'd like to address is the requirements of adequate standards and incentives for generator dynamic reactive performance. I need to emphasize that requirements that apply to generators that deal with power factor, those things are only providing for the static, long term steady state capability of the generators.

We're concerned about the dynamic response of generators and other sources to voltage disturbances. The dynamic portion of a system disturbance is that portion that lasts for several seconds, beginning at the moment of the onset of the disturbance, and going out for, perhaps, as long as 20 seconds, and maybe even 30 seconds. But primarily in the first 10 to 15 seconds the performance of the dynamic reactive devices on the system are very critical to whether the system can recover from that type of disturbance.

And in particular, as applies to conventional generators, which are typical synchronous machines. Those devices are capable of delivering several times their rated reactive capability for a brief period of time. And that response is extremely important in recovering from severe voltage depressions in possible cascading situations.

So, in that regard we would want to suggest that any effort moves in the direction of compensation for reactive power production recognize those difference between the static and dynamic capability. And also recognize that there are differences between different dynamic reactive devices. For instance, a generator with a rotating exciter can respond much better under low voltage conditions that a generator with a static exciter. That's a situation that's understood in the industry. And what we see is that the generation that's coming in to displace the conventional generation typically has a static exciter, and the machines are being retired have a rotating exciter. As a result we see in our simulations that the period of time required to recover the system voltage, let's say to 9 percent level is getting longer as a result in that type of change in the dynamic reactive device characteristics.

CenterPoint Energy would suggest that one way to address this would be establish dynamic performance requirements for generators as a reliability requirement to participate in electric energy markets. That incentives be established for generators that provide high performance dynamic response under depressed voltage conditions. And that transmission criteria be established that would provide for transmission system dynamic performance; and that would improved certainty that utilities would allowed to recover costs associated with stand-alone dynamic reactive devices that were required to support the transmission voltage levels.

I guess the final comment is with in regards to the issue of compensation for dynamic reactive services, our position, is that any compensation or incentives should be based on demonstrated capability. Very frequently we find that generation resources, for various reasons, may be limited to a much lower level of output than what is theoretically possible. For instance, we looked at the generator capability curve, and that can come about for many reasons. Some of those have to do with transmission systems, some of them have to do with the configuration on the generation and its auxiliary components.

At any rate, we feel that the compensation incentives should definitely be based on demonstrated performance, either through tests, or actual observed performance response to system disturbances.

That concludes my opening remarks. Thank you for your attention.

MR. O'NEILL: Mr. Snead.

MR. SNEAD: Thank you and good morning. My name is Ron Snead. I'm speaking on behalf of the Midwest ISO Vertically Integrated Transmission owner, probably referred to at VITOs, and I try to not say that all the time. We appreciate this opportunity to have a chance to address the Commission and Staff. We certainly would like to extend our commendation for the exploration in this area.

The VITOs serves loads which make up about two-thirds of the Midwest ISO load, many in the control areas. Many of our issues really to us are the cost and reliability issues that we see at both the transmission owner and a load serving entity.

To start with we believe that a generator should not be automatically entitled to a reactive power fixed charged payment simple because it has the equipment necessary to produce reactive power. We believe that should it be established that the reactive powers used and use for these costs are charged to consumers. It's not unusual for an entity choosing a location for its generating facility to make the selection either transmission availability or fuel availability. And this may well create a situation where a generator is located in an area where the graft power is simply not required for system security.

In contrast we would also believe that a system generator, after consultation with the entities responsible for system security, such as the RTO would locate a generator where there is a true need for reactive power. The generator should be compensated for doing so. Also due the current rate design for reactive power compensation we believe there is an issue in certain areas where generators choose to locate because of the availability of either fuel or transmission. But the amount of generation far exceeds the load of the area.

In instances where the amount of generation may well in excess of the load of its own, it may not be reasonable to allow reactive power to charge STV assigned directly to the location zone, as it would expected that any generators would export to other areas.

In addition while the VITOs agree with the principles of comparability, we do not believe all generators are equal in providing reactive power. Transmission providers, obviously, need reactive power to be available on an instantaneous basis. As a result, we believe that units that are running are spending most of the time on more valuable overall than a generating unit that is only on-line during limited times of the year.

A generator that is on-line and running can provide instantaneous load support, whereas an off-line unit would obviously need to be started up to provide this voltage control. It may be where we have a situation where an off-line generator by the time you got it started and synchronized to the grid the need for the reactive power may have already passed.

We view it more as a significant rate design issue where all of these factors have to be taken into consideration, such that they reflect in the E-4 of the value-ability of reactive power produced by the unit.

Also, in the VITOs view it is critical that a unit receiving payment for reactive power be available to inject and absorb reactive power only required by the transmission provider. Therefore we believe there should be a penalty system to encourage generators to be operational and controlling voltage when needed.

While certainly there are a lot of details you have resolved in order to develop an effective penalty system, we believe there are some important elements that should be considered. First, we do not believe that cover the type of damages that would provide for the cost of replacement energy be sufficient. Reactive power is such a critical element for system reliability it must be supplied when and where required.

So, we would be concerned that simply paying for redistribution may not be sufficient due to the critical nature of reactive power. We believe that such penalties could include suspension of capacity payments for reactive power, as well as covering costs resulting from the generators failure to supply reactive power.

You could also consider revocation of capacity payments if the generator failed to comply with the transmission providers instructions a certain number of times. We also believe that there is a clear need for testing guidelines to ensure that the generator can produce the reactive power for which it is getting paid.

Finally, it is critical that the operating status of the generator be known to the transmission provider. The transmission provider must know whether a generator would be available to provide reactive power on both and instantaneous and delayed basis, and how much reactive power the generator could provide.

VITOs are concerned with the current reactive power restructure don't accurately reflect the differing contributions of generating units for producing reactive power. A unit that is operating most of the time is available to provide the instantaneous reactive support that I mentioned earlier, basically gets the fix -- gets the same fixed or similar fixed charge payment as a unit that doesn't run as much. So, we would believe that based on the value to the system there should be a distinction drawn between these generators. Given there is an important redesign issue, we have had some internal discussions on it, but we don't have a proposal at this time.

The VITOs strongly support comparability, and we believe the comparability should consider factors such as, need and location. There are some transmission owners that do not currently include PP units in their reactive rate so they do have some concerns about convertibility for compensations for PP units.

The Staff paper suggested that there may be FERC sponsored for determinate reactive power sources. We believe Commission should solicit input from the state commissions on this issue, as the states have in the past exercised control.

I would to extend our appreciation for this opportunity. Thank you.

MR. O'NEILL: Thank you, Mr. Snead. Mr. Calimano.

MR. CALIMANO: I'm pleased to represent the views of the ISO RTP Council. Members are the CEOs of California ISO, New England ISO, Midwest, New York, PJM, SPP, and ERCOT from the United States; and from Canada the CEOS of Alberta and IESO Ontario.

We will present some initial comments, we'll submit some paper by the April 1st deadline. Reliability considerations must be paramount. I'll start by stating reliability considerations must take precedent over economic and pricing considerations in the management of reactive power resources. Reliability aspects of reactive power must be fully reflected in the design and operation of the volt power system.

We note that the Staff report is devoted to the economic and pricing aspects of reactive power. The ISO RTOs are aware of that from the market-base environment reliability and economics are both important and related. Failure to get the economics right will create reliability challenges. But the paramount points of reliability must not be lost on those reading the report.

Each ISO RTO is developing its system reliability plan. It considers the adequacy of reactive resources, and establishes the best available solutions for any deficiency. Potential solutions include generation in transmission options. They are fully described in the Staff's report. The result is that all the ISO RTOs have in place adequate reactive resources to maintain reliability then there is no pending crisis.

At the same time it would clear that the ISO RTOs aren't complacent and we place high importance on ensuring the adequacy of these reactive resources.

Recommendation number one was reactive power reliability needs should be assessed locally based on clear national standards. We fully support the NERC continent-wide standards on voltage control, with appropriate regional differences considered and regional standards applied.

We note that NERC has defined reliability standards relating to voltage control and reactive power in its (inaudible) zero standards. This is a good first start, but there's more work to be done in the future.

We also agree assessments must be done on each local area. Localities within each RTO territory may differ significantly with respect factors such as related amounts and reactive characteristics of both generation and load availability and the matter of reactive support. And therefore is essential that planning assessment to the local area reflect their diversity.

The ISO and RTO currently do assess on a locality basis. The generator, in fact, and the owner of a reactive power device connected to the volt power system must be required to follow directions regarding reactive power production and consumptions from its reliability coordinator or its transmission operator.

The generator must be required to operate a voltage control load, unless directed to the contrary. ISO New England load power factor correction requirements, although not discussed in the report, but should be considered in best practice. New England is divided into reactive analysis zones, each of which has a maximum and minimum load power factor during peak loads. Keeping within this range is the responsibility of the local transmission owner. This requirement results in the deployment of static reactive devices on a distribution system, which is more cost effective than anything that's in the high voltage facilities. This approach is under consideration in New York.

A comprehensive analysis of reactive requirements should include evaluations of the use of reactive devices on transmission system, for example, shunt series (inaudible) SBC, et cetera. And there is a need for an improved comprehensive testing of generation and transmission reactive equipment.

I'll make a general comment on pricing aspects. The price of reducing reactive power, are and will always be, small in relationship to total energy costs. In New York, for example, compensation to generators for reactive power is more than one percent for the total revenue of the New York energy markets.

The largest benefits to customers will not come from reducing the costs of supply reactive, but rather the optimal deployment, to be able to transport additional loads of power, reduce losses, and reduce congestion caused by voltage constraints.

There needs curative reactive in an efficient reliability manner. We note that ISOs RTOs have quite similar processes for procurement of reactive power using cost-base compensation methodologies. Most compensate generators for lost opportunity costs when real power must be reduced. Most compensate generators affiliated transmission owners and IPPs. Most have established the same or very similar power factor ranges. Most have developing reactive power testing criteria.

There, however, differences among the ISOs as the report documented. In our view the differences should not be viewed as a problem to be fixed. We believe that it would appropriate to move to uniform practices at least not to arrear term. Current rules and contractual arrangements are extensive, interrelated, and should not be replaced unless there is a clear business case for doing so.

Of course, the cost of reactive resources are relatively low, and it's not obvious that there is such a business case. The differences reflect the fact that each ISO RTO has a unique historical evolution stakeholder process. Intrinsic differences between the regions, for example, in load behavior and dynamic characteristics.

An important point is that despite minor differences in approach each jurisdiction meets the objective in picture of reactive power procurement. However, we fully accept the on-going need to review our current reactive practices in identifying best practices for each region. Report details two pricing options, capacity payments for real-time pricing, noting capacity options employed on most all existing cases. We would not rule out proposed market desire at this early stage, but we recommend continuing a cost-based approach, at least in the near to medium term.

Reactive power market would have far great challenges than a real energy market, because reactive resources are effective only in the immediate local area. Accordingly and recognized by the report the potential for local market power problems could be substantial.

The report notes five to ten years may be required to implement market designs, and we believe this is a realistic time frame. Real-time pricing methods would likely require reactive load zones similar to LMP zones for any new pricing. Given local nature of reactive power there may be need for far more reactive zones than real power zones.

Again, we wouldn't rule it out, but we would want to move cautiously. Overall we believe the ISOs and RTOs currently have a fair and effective cost based approach, which provide adequate supply of reactive resources to ensure system reliability.

With regard to who pays, end users pay

directly or indirectly for the cost of producing reactive power. Transmission reactive facilities are reflected in the tariffs based on monthly using charges. Generated costs and revenues included in ISO and RTO tariffs, such as those in the Schedule Two are reflected in the cost of transmission service, and therefore the costs of power to the end user.

While we note end users may be primary beneficiaries of reactive power, generators benefit from resulting a more stable power system, and fewer trips. All power providers should be paid on non-discriminatory basis. Generators are generally compensated in the same manner given and ISO RTO jurisdiction. IS in New England has identified mechanisms to broaden the base of supply by introducing load size solutions. For example, load customers that we install dispatch reactive devices.

As I said before, we'll be filing official comments by the April 1st deadline.

MR. O'NEILL: Thank you Mr. Calimano. Mr. Bose.

MR. BOSE: Good morning. I'm Anjan Bose. I'm from Washington State University in Pulman, Washington. I'm the Dean of Engineering there, and I work in the area of power system reliability and control. I'm also part of a multi-university research center, call the VAR System Research Center, which has about 13 universities working together in the area of power engineering, and it is supported by the National Science Foundation and about 35 companies in the power industry.

All that is pre-ample to saying that I don't represent anybody here, except myself. In any case, given that you already know two professors wouldn't -- not unlike economists, two professors actually wouldn't ever agree on anything. I couldn't possibly represent the researchers -- the academic researchers in this area.

I am, however, going to limit my comments to five minutes. So, I will make only two points. And as you know, that's hard for a professor to do. The one thing I will comment on is, the obvious slant of the report, that is the report, has a viewpoint which looks upon VARs as resource. Okay. And so I am going to talk about that a little bit, some comments on that. And then I'm going to talk about what is the service that you're trying to provide for which you will compensate the providers. Is it really VARs or is voltage control? So, those are the two points I'm going to talk to.

First about the VAR as a resource. One of the reasons, of course, that the viewpoint is taken by the report that VAR is a resource is because we are trying to come up with a market, or to at least check whether there can be a market in it. So, as a resource or as a commodity, what is VARs? Well, one of the problems that you run right into in the beginning is that it is not very clear what VAR is, because it's sometimes looked at as an imaginary quantity. But essentially, it's a mathematical construct to explain the fact that voltage and currents are sinusoidal, or they are not DC. So, if you think of it as a mathematical construct there's no particular reason to actually thinking of that as the resource. You could think of something else as the resource. For example, if you think of the power as being a complex number, you could represent it as both real and imaginary. You could represent it in polar coordinates. And what would you measure in that case?

Just because it can be measured, and of course, we can measure VARs, doesn't mean that it is something. It is still a mathematical constrict, because the way we are measuring it is actually measuring voltage and current, which are real electrical things, and then multiplying them in a particular funny way to come up with a number called VARs.

So, I think -- my only point here is that, is it a resource? What is it? Okay. And that's a question. Added to that is the fact that VARs, most resources that you buy and sell happen to be only positive. That is they go from zero to up. They don't go from zero to negative, which unfortunately VARs do. That is generators produce VARs, as well as absorb VARs.

Not only that, almost every part of the power system does the same. Transmission lines produce VARs as well as absorb VARs, so does the distribution system. So, now -- in fact, I was going to take a little issue with the statement in the report which says that VARs are needed to be produced to hold up voltages. Well, sometimes VARs need to be absorbed to hold up the voltages. Some of them get held up too high. In fact, there are conditions under which you want the system to actually absorb VARs.

The third point I want to make, and this is dealt with a lot in the third point under the resource issue, is the issue of static versus dynamic. This point is made very well described in the report. But I think once you start worrying about how to come up with a market for a dynamic resource, you run into the same problem. And, in fact, more so in the case of VARs than you have on the real side. That is, frequency control or generation control is, essentially, the same concept, where you have to have a dynamic source of real power.

And as you know it's been difficult to have a market that reflects the dynamic part of it. Most of it has been done, most of the markets in generation control or frequency control is done by considering capacity. And sometimes that capacity is defined as being able to meet a certain dynamic rate. That is, we all know that hydro does better at frequency control than does a nuclear plant. So, you put certain categories on these capacities that you count.

Probably, the only country that I know that has gone further in this is Australia, which has defined something like four different categories of dynamic real power availability. So, as you go into the reactive power you are in much more problems, because you are not just talking about just one kind of dynamics in reactive power. So, those are sort of looking at it as a resource.

But the other point, as I said I was going to make, what is the service you are providing, that you are going to compensate for? Is it VARs or is it voltage control? Because everybody here mentioned that voltage control is what is important for the reliability of the power system. And ultimately you are trying to pay for holding up that reliability. The main reason you're worrying about VARs is for the reliability, which is provided by the proper control of the voltage. Now, there is an obvious relationship be VARs and voltages. But it is not a direct linear kind of a relationship. In fact, the first order of proximation, which defines the linear relationship between voltage and VARs is very, very approximate. Much more so than we assume in the area of real power and angular difference between the load. I mean that approximation is much more accurate than the one in the voltage side between VARs and voltages. And so you have to worry greatly about that.

And finally, one other point, on whether it's voltage control or reactive power is that you don't necessarily have to have reactive power to control the voltage. I mean, transformers control the voltage. And that's neither a source, nor an absorber of VARs. So, there's a whole issue about if you are going to provide a service for which you need compensation, I think it is easier to look voltage control as the service, rather than VARs, which is one stepped removed in a proximate way to the voltages.

Having said all that, I will conclude by saying that I'm not trying to say that there shouldn't be a market in either voltage control or VARs, I've personally written papers on the subject of markets and

VARs and it has been quoted in the report.

But there are many ways to skin this cat in terms of defining what it is that you are going to compensate for. I'll stop there. Thank you.

MR. O'NEILL: Thank you. Mr. O'Connell.

MR. O'CONNELL: Mr. Chairman, members of staff, I'd like to thank you for the opportunity to come here and speak on the subject. If you are looking for me to provide some clarity to Dr. Bose's comments, I'm going to have to pass to the next speaker.

The FERC Staff's technical report on reactive power is a comprehensive assessment of the state of the technical and regulatory issues surrounding planning, operation and commercial aspects of reactive power. The six problems and concerns regarding the practices procurement and pricing policies and the four broad recommendations identified are important issues to merchant suppliers.

Every category of participant in the market, transmission owner, generation owner, load serving entity, distribution owner, and end use customer has the potential to provide reactive power. From a jurisdictional standpoint there are potential inconsistencies between federal and state jurisdiction. As one of my colleagues mentioned, we can have it set up where end use customers, in essence, have an opportunity to provide VARs. However, because their service is driven by state retail tariffs, if we have a difference between compensation, the wholesale side versus retail side, where everyone is not reacting to the same pricing signal. So, that's one of the things I think we need to look at as we go forward.

Clearly, merchant suppliers can and do provide reactive power, yet they are not always compensated in a direct manner. Some stakeholders have an interest in maintaining the status quo, which does provide for comparable treatment. We are convinced that those who provide reactive power either, actually delivered or maintained in reserve, should be compensated and the basis of that compensation should be the value of the service provided.

In our view the transmission owners is the linchpin of the current reactive power paradigm. The transmission owner has influence in many different areas as it relates to this. They influence the planning policy, the planning standards, and the design of the transmission system.

The transmission owner influences the type, amount, location of reactive resources, even through the development of models that are used to perform technical studies to quantify the reactive power needs in the system. The transmission owner influences compensation mechanisms, and that's probably one of the reasons why we're here today to talk about the subject.

The transmission owner and its affiliates are potential suppliers of reactive power. And if they're integrated with the distribution company, the transmission owner has certain service standards that they must comply with for the end-use customer. That's why if there is some kind of disturbance that causes a refrigerator to fail, if you can prove to the utility it's because of their failure, they will help you in some shape or form to get a new refrigerator.

If we look at some of the issues what contributions restructuring has made or caused in this area, one of the sources that I looked at in this area was a report put together by the Michigan Public Service Commission in its review of the August 14th blackout. In there the Michigan Public Service Commission is quoted as: "Placing authority or any significant control over grid reliability decisions in the hands of companies with a commercial interest at stake must be prevented." I think the merchant power industry believes that that is an important point as we proceed forward.

In some cases I think there is insufficient understanding of the importance of reactive power, and of the behavior of load in consuming reactive power. If we look back historically in many different failures in the system we'll find that after the fact engineers found that load was behaving in a way they hadn't really understood that it behaved. And understanding these behaviors is one of the things that we need to proceed with if we are going to come to some kind of real-time, measurement in real-time obligation setting for reactive power.

In most instances, staff in generating stations are, generally, aware of the need to control voltage at the bus they are connected to, but they may not always understand the importance or reactive power production, particularly when emergency directives are issued to change voltage in one way or another.

A more thorough understanding in all participant paradigms in may help in more creative solutions to the problems that we have. I also think that engineers, both in planning and operating need fully vetted tools and techniques to resolve assumptions that we have heretofore left unchallenged.

All generators can and do provide reactive power, regardless of ownership. Synchronous generators use the same approach. The generator controls voltage through a voltage regulator, and that voltage regulator is, essence, changing the amount of reactive power that's produced.

I agree with Dr. Bose that really what we're talking about is a service. And that service is to control voltage. And by issuing a voltage schedule, which is something that the transmission owners do for every connected generator, what they are sending to the merchant is an order for a variable amount of reactive power, depending on the voltage that is being controlled. And that amount of reactive power changes as system conditions change.

Merchant suppliers are required through the provision of interconnection agreements to produce reactive power. One example of this, I cited from an interconnection agreement between Tenaska Alabama Partners and Southern Company Services. I quoted from there, "When Tenaska is connected or delivering power to the Alabama Power Electric System, Tenaska shall operate its generation to meet the voltage schedule, as measured at the 500 kV transmission bus serving the facility, provided by Alabama Power. If Tenaska cannot hold this voltage schedule but is producing the maximum about of mega-VARs, then that is acceptable performance." Excuse me.

Some interconnection agreements require merchant suppliers to replace reactive power in the event a facility can't produce what it was designed to produce. And example of this is in Kinder Morgan Michigan's interconnection agreement with Michigan Electric Transmission Company. And I quote from there, "In the event the facility is unable to consistently maintain a reactive power capability sufficient to maintain a power factor at the point of receipt within the facility's reactive design limitations, the generator shall take appropriate other steps to configure to meet such standards, including as necessary, the installation of dynamic reactive power compensating devices subject to prior review and approval of transmission owner." Yet these merchants don't receive any payment for this service.

From an operational perspective, dispatchers prefer to have reactive power in reserve as much as possible, because that gives them much more flexibility to respond to conditions that none of us were smart enough to figure out could occur.

We have them at all times, and ample reactive power reserves are one of the tools the dispatcher can pull off the shelf immediately to help in figuring out how to stabilize the situation and then go onto its next steady state.

Merchant suppliers are committed to supporting the reliability of the electric system and stand ready to do so when called. Merchants must respond quickly to fill the needs of the market. Merchant suppliers also respond to any request from the control area dispatcher because of the requirements in the interconnection agreements.

Merchant suppliers make a substantial contribution to reliability through their integrated operation into the transmission system. This fact, once again, was identified in the Michigan Public Service Commission's report. And I quote from there in talking about the recovery periods right after the August 14th blackout. "The return of generation at the Whiting facility and the restarting of generators at Kinder Morgan power plant were top priority. These units provide both local power supply and area voltage support."

The Kinder Morgan plant is owned by an affiliate of Kinder Morgan, Inc., which is primarily a pipeline company. The plant disconnected from the grid on August 14th at 16:10 Eastern Daylight Time as a result of the voltage collapse, and it reconnected to the grid 38 minutes later. Even though it was one of the first plants to respond to the recovery efforts in that region it took the merchant over three months to find a party willing to accept cost responsibility for the recovery efforts, for the cost operation of the plant. And in settling up with the Utility, not only did the merchant receive insufficient compensation to recover its costs for the energy produced, but the value of the service it provided then and continues to provide remains wholly uncompensated. And from our perspective as a merchant, that is a significant issue that must be addressed.

Merchants support mandatory performance testing requirements for generators to receive compensation. However, we are concerned. Some transmission owners have crafted these requirements to exclude from compliance significant portions of the generating facilities in the system.

Merchants believe all generation should be required to respond to these compliance requirements. Merchants support the concept of performance testing for service so inextricably linked to reliability as reactive power supply is. However, merchant suppliers believe the standards and metrics must be fair and transparent.

The industry needs a new paradigm to move forward. The end of selective compensation must be at the forefront of this effort. For many the need to provide reactive power has already been established within the interconnection agreements. The transmission tariffs must address compensation payments. Compensation mechanisms must eventually include differences in location, in resource type, whether they are static capacitors, static VAR compensators, synchronous condensers or generators, and in control capabilities. The payments need to recognize differences in values.

The system of the future must clearly encourage all market participants to make decisions that result in the right outcome. These participants should expect to receive and must receive a reasonable return on the investments made in that regard. We recognize the challenge in revising current mechanisms. We emphasize that the following elements of tariff redesign must be considered and reflected in every open access transmission tariff.

All generators should be given the same opportunity to provide reactive power. Reactive power should be provided and compensated on an unbundled basis. Compensation for reactive power should be based on its value to the market. The current cost-based approaches are reasonable relative to the cost of other reactive power resources, and they are acceptable as an interim solution to price discrimination. Efforts to qualify suppliers must not be allowed, to protect the historic suppliers while disadvantaging bona fide potential merchant providers. The customers must be given the opportunity for self supply.

I thank you for your time.

MR. O'NEILL: Thank you, Mr. O'Connell. Mr. Howe.

MR. HOWE: Thanks very much. My name is John Howe of American Superconductor. I'm substituting for Terry Winter of our company who could not be here, unfortunately. Unlike Terry, I'm not an engineer. So, I will do my best to present our views on technical issues in non-technical language.

I wanted to say at the outset, this is a critical issue. Several people have said that. The Staff report is really a fine piece of work. One of the most thorough that we've seen. And because others on the panel have covered much of what I had prepared on, I can concentrate on the role that distributed mobile, relocateable, dynamic VAR devices can play, and in fact, are playing in today's system.

Now, I read in the report that you all want to make the rules that you come up with technology neutral, which is an important objective. Likewise, we as a developer of innovative technologies would pause it. The technology in and of itself is policy neutral. Nevertheless, the rules that you all come up with are going to have a critical impact on the extent to which users of new technology solutions can see the value, can quantify the value and can capture the value of using these new approaches. So, we naturally take a great interest in what is happening here.

Now, several other people have described the factors that are leading to an increased need for dynamic reactive support on the grid. We've heard about the growing siting difficulties, building new transmission and generation. Competitive forces are driving the retirement of a lot of older urban generation. It's just rising load in general. All of these factors are combining and let me use a non-technical analogy. I kind of this problem as if, you're driving down a road at night and you hit a patch of fog, and you know that there is a pothole ahead, but you don't know where it is. In a situation like that, it doesn't really help to have more horsepower. What you really need are shocks and struts. We think of the solutions that we're developing as shock absorbers for the grid, flag wheels for reactive power. I mean there is just the ability to handle those unanticipated transient events on the grid, allows you to operate the underlying system to a higher level of performance. Now the staff report has done a really good job of describing a whole range of technologies, ours and other's. To mention them by name, the Dynamic VAR systems which are power electronics based. Distributed SMEZ, which includes a superconducting magnet to provide a reservoir of real power. And we are currently developing a proto-type of what we call the Super VAR Dynamic Synchronous condenser, a rotating machine that can provide a high level of overload. And because it is superconducting it is more efficient, much lower internal losses than a conventional synchronous condenser.

Some of the applications, just to go through them, studies that we have conducted or installations that we have. These technologies can be used to very cost-effectively increase imports into congested areas, load pockets, transfers across the grid, exports from supply bubbles. I think though this is going to take -- this is an area we have not seen applications because there are regulatory disincentives for utilities that may have bottled up low cost generation, but if the rules were right, this could provide an effective solution to allow bottled up low cost power to reach broader markets. An area that generators and exporting utilities would have an interest in. Flicker, a problem with a lot of new manufacturing techniques. Interconnection of Wind, we now have about eight dynamic VAR devices at Wind Farms across the United States, Canada. One on the Organdy Islands of Scotland. So think about the peripheral areas of grids where you have to have a local source of voltage support. Generally, reinforcing transmission system reliability, and in particular, improving local reliability and power quality so that you can avoid altogether the need for under voltage load shedding.

If we can avoid the need to invoke those schemes, I think customers will be a lot happier. Now, I'd like to point out a key fact about these technologies. They do provide steady state voltage support. But their real value is in the transient response, literally sub-cycle, millisecond level response. And I just wanted to cite one example. You may know, I think it's been five years now, we've had seven of these distributed SMEZ devices operating on the grid in Northern Wisconsin. This is in the area of where the Arrowhead/Weston line is proposed to serve. The Utility needed an interim fix, and looked to this as a short-term solution. Of course, as the siting of that line is extended over years, these assets have been critical to support reliability in that area.

These magnets over the course of five years have fired thousands of times, never have they fired for more that 23 cycles, which is about 400 milliseconds. And I think what that shows is the value of having very immediately available reactive resources that can respond and kick in to compensate for voltage fluctuations.

Now valuing resources like this is problematic, if you are looking to create a market framework. At the instant when it is needed, the value is nearly infinite. And if you were to compensate them on the basis of the value at the time they provide at the moment they're needed, there would be, I think, some serious ratemaking problems.

I would like to use another analogy here, and that is that -- I think that we have heard from several of the experts on this panel, there's disagreement on whether there is a viable market for reactive power. Reactive may not be a product in itself that can form the basis for a market, but it is critical to support the functioning of the real power marketplace. So, I would like to draw the analogy to other public services. I think of fire and police protection, which are government services that are not provided by the market. We do not pay our policeman on the basis of the number of bullets that they fired to prevent bank robberies. That would create, I think some serious traverse incentives.

(Laughter)

MR. HOWE: But we put them on a salary and they provide continuous protection. Their presence in the community deters a lot of crime and enhances the sense of public safety, which allows other people in the society to go about their own business and allocate their own resources to their highest and best uses.

In the case of fire protection, it is true that for a long time many communities in rural areas had volunteer fire departments, but as our society has developed, in an urbanized complex society, has professional fire departments. We can't really effectively depend upon volunteers to provide all the services required. In fact, it simply wouldn't work to pay people the opportunity cost of leaving their day job to fight fires. Instead, we rely on professional fire departments. We rely on fire codes, building codes, sprinklers, other, effectively, passive approaches that minimize the occurrence of the problems that you're looking to prevent. And these professional firemen, most of their time they are not fighting fires. Most of their time they are out there doing inspections, and they're doing what is necessary to reduce the instance of these problems.

Now, I understand the impulse to want to create market solutions and certainly at least cost solutions. I think that is really is the objective of a market approach. But since there is an agreement on whether a market framework for reactive is possible, I would just urge not to make the pursuit of the perfect here become the enemy of the good. There are several interim step, or intermediate steps that the Commission can take to encourage more effective approach to the issue of dynamic reactive support.

The Staff report mentions the need for clear and uniform standards, which are applied appropriately to local conditions. And I would urge you to go down that route. Certainly, clear standards will help everybody.

There needs to be encouragement of more investment in this area, dynamic reactive resources. Now, let's recognize, of course, many of these investments are state jurisdictional, and because of long-term state rate freezes there has been a disincentive for utilities to take on investment in this area, I think in some cases. But appropriate rules that encourage the use of distributed and dynamic VAR support can in many situations lead to much more cost-effective solutions for reliability problems. And I can point from our own company's experience to situations where we've helped utilities solve reliability problems for ten times less than say building local generation. And there is the advantage -- I mean these are compact trailerized approaches. They engender no siting controversy, no air impacts, because they just plug right into the system. Not only are they a low investment cost, but also there's a minimal risk of stranded investment, because they come in a truck.

One of the things we're going to need to do in the future is configure systems such that they can be reconfigured from year to year in response to changing conditions, shifting loads, generator retirements, addition of new generators. Relocatable approaches to dynamic support will allow for much more cost-effective and flexible solutions.

And I think from an investor standpoint this approach would promote much more efficient use of existing assets. So, as we see it, it's a win for consumers, with better reliability and lower costs. It's a win for grid owners, with availability of more tools. It's a win for investors in existing generation, which will be more effectively used. And also this is an approach that could allow us to avoid the need for new investment in generation, which would only be used sporadically. In today's market it's very difficult to finance new generation that's only be used on a sporadic basis.

So, I urge you as you go forward in developing these new rules and approaches as a test of whatever framework you come up with, consider how it will impact the market opportunity for some of these innovative approaches. Thank you very much.

MR. O'NEILL: Thank you. Mr. John.

MR. JOHN: Thank you. As a representative of AEP a large equipment manufacturer, I'm planning to speak about FACTS, or flexible AC transmission systems. FACTS have many roles and benefits through the controlled production and consumption of reactive power. Some of these benefits have already been described, things like post-fall voltage control. The ability to avoid a voltage collapse by providing the right amount of reactive power immediately following a system contingency.

FACTS can also improve blackstar capability in the case of wide area outage. And FACTS also have the ability to provide nearly instantaneous voltage for power flow control. A key feature of FACTS is that they provide dynamic reactive power. They are not a static source like capacitors. And in this way, FACTS can act like a generator in terms of dynamic voltage control. Let me elaborate on this point a little bit with an example. Reliability must run for RMR generators are often used for reactive support or voltage control rather than real power production. FACTS can be used in lieu of an RMR generator to provide voltage support and allow power to be generated from distant sources, but often more economic ones.

This is particular beneficial in load centers, where issues like siting, emissions aesthetics, fuel delivery and so on are a challenge for generators, but FACTS don't face any of these issues. I think as Mr. Howe mentioned, they plug right into the grid, and they don't consume any fuel. This type of application has been demonstrated in Austin, Texas; San Francisco, and on the DelMarva Peninsula. And in fact, in the cases of Austin and San Francisco generators have been shut down and the land reclaimed for public park use without compromising system reliability.

Let me elaborate a little bit more on the economics. FACTS in many ways are light conventional transmission equipment in that they have relatively high capital costs, and low variable costs. Of course, this contrasts with conventional generation which has both high capital and variable costs.

To optimize the cost of real-time generation dispatch FACTS can be used to avoid running otherwise un-economic, highly inefficient generators in times of local locational reactive power scarcity. If the goal is to optimize the cost of real-time dispatch, it will be advantageous to treat FACTS devices like transmission equipment and assume it capital cost recovery, to assure the availability for reactive power voltage and power flow management.

Further, if FACTS is treating like transmission equipment it will be under the control of the grid operator, rather than an independent entity, ensuring -- or avoiding market power and conflicting incentives.

As many of the previous speakers have stated, reactive power does not travel well. So, it must be produced and controlled close to where it is needed. Because FACTS is space efficient and non-polluting it is it much easier than generation to site in urban areas and congested load pockets.

And if it is better to retire an inefficient urban power plant for bad economics, it may be better to replace it with a FACTS device, rather than to convert it into an equally inefficient high maintenance synchronous conductor.

In conclusion I would like to say electric reliability is a public good. I think we can all agree on this point. FACTS enable more efficient use of generation and transmission while maintaining reliability. Therefore, FACTS should be procured as public good, and included in the rate base like other transmission assets.

MR. O'NEILL: Thank you and thank all the speakers here today. I will refrain from making comments about a market since this is a reliability technical session. We'll talk about markets later on today. I'd like to try and focus on reliability and technical issues first, and then if we have time we can talk about markets. But these next two sessions were more to focus on that.

We're open for questions. John.

MR. KUECK: Yeah, a couple of the comments I heard that I really agreed with were in the future, maybe five or ten years down the road there might be a need for reactive zones than real power zones because of the fact that reactive doesn't travel well, and because in some areas load pockets or potential zones for voltage collapse or reactive power, especially dynamic reactive power will have a very high value. But on the other hand, a comment that I heard was that the existing voltage schedules are really an order for reactive production, and that's true. That existing voltage schedules drive of reactive power, and in some areas there are first contingency voltage schedules where the voltage is very well specified and defined post-contingency for one contingency.

So, the question I have is, if all of those are true, the voltage schedules are pretty evenly spread. But these reactive zones are going to be pretty tight, in some cases depending on a great deal of analysis. How do we get from A to B? How do we get from this voltage schedule being an order for reactive production, and maybe a first contingency schedule being an order for reactive production down to understanding the need in small zones?

MR. CALIMANO: I guess I will try that for the first one. Production of the voltage schedules for availabilities will take into account, as you said, first contingency audit. Requirements are where they need to voltages according to those schedules based on reactive resources there.

When we talked about load zones or reactive zones we were into a situation we ran into a situation where there is a market operating. In the marketplace there is competition for who supplies the reactive. And what we covered up these zones, some of these zones because of the only one market play, will it reduce it self on a market power review sheet. So, I think when we were talking about zones, we were really focusing in on the market side of the house. And market power issues associated with zones, and who can supply it. Case in point, to raise voltage one kV in one location may require 50 megawatts from a generator right there. If you go 200 miles away it may require about 500 megawatts to raise it.

So, in the small zones it's really the market power issue that's really addressing it. Voltage schedules in cost-based system will take reactive from any source, but there isn't a competition going on for that, since you paying on a cost-based system for it.

I think moving from both the schedules that we produced now on a cost-based system to small load zone was really going into a market competition for reactive support, and having problems with ability to supply reactive for long distances.

MR. O'NEILL: Can I get a clarification? I mean, we always hear that reactive power doesn't travel well. But certainly line loading reactive power probably travels, maybe, too long.

MR. O'NEILL: It depends on which -- just like voltage schedules, there are contingencies that produce low voltage, and contingencies that produce high voltages. Yes, under light conditions you may have too much reactive power. It may change very well.

MR. CALIMANO: If you looked at the amount of reactive power that went into one end of the transmission line and the amount that came the other end you'd find that it could actually travel -- it could replicate itself. It produced reactive power, if you will. (coughing, inaudible). In a New York system we have a tendency to load transmission lines well past their surge and peak, so we are losing more reactive than producing.

MR. O'NEILL: It's not traveling well, like you said, high loadings on the transmission lines.

MR. CALIMANO: Correct.

MR. BOSE: That's correct. Even in New York I suspect if you look at New York City, you've got all the tables, which would probably produce more VARs in the nighttime more than any other time. But to go back to your question, I don't think there is a particular contradiction between finding zones and fixing the voltage targets. Because the way the zones are found, this sort of zonal control has been tried for many more years than here in France, Italy, and Belgium. And unfortunately, they started out looking at the zones as geographic zones, which didn't quite work. And now I think they are reverting back or going to a zone that is defined by voltage sensitivity from the sources. And if you define it that way, define your zones in terms of voltage sensitivity to the VAR sources you will find that setting the targets for next day, it works pretty nicely with the zones as well. When I say nicely, anything you do with voltage and VARs is first order of proximation. It's never perfect.

MR. SINGH: I think one of the speakers said that capacity payments should not be given to all generators because, I guess, the VAR support that one generator is different from another, depending on its location. So, the flip side of that would be, should interconnection requirements in terms of (inaudible) factor also vary. And I'm just wondering, is that technically even a good idea to think of GE making generators that every generator is different. So, if you have thoughts on that, I'd like to hear it.

MR. CONNOLLY: I'd like to make just a general comment relative to the whole issue of the locational nature of reactive power. You know as an industry we've done a great job in designing the AC power grids to be very efficient and have low losses with respect to real power. They are actually quite high loss, very lossey with respect to the reactive power. That's the fundamental reason why the locational issue is such an issue for reactive power. For instance, a typical transmission line may have losses that are ten times the level for reactive power delivery as far as real power delivery. When you get the transformation boot, like transformers that ratio can be as high as 100 times the number of losses. That's just the nature of the AC system that we have and we have to deal with.

My own concept an the issue that we're dealing with in ERCOT is from a capacity standpoint, these locational issues make it very difficult to come up with an equitable compensation schedule. At least initially in our ERCOT we were handling that just by having a requirement that it be available. And we defined the requirement on the part of the generators, the requirement on the part of the transmission device, the requirement on the part of the distribution device. And then there was wording from there on the issue of how to compensate for delivery of reactive power.

But that capacity issue is very difficult because of that locational nature. Somehow you have to temper the capacity, deliverability, how to compensate the capacity.

MR. MCCLELLAND: Is there a -- and this goes back to your point, Mike, which hits me, I think there is an interesting correlation between distribution transmission, and then you can split the transmission in to static and dynamic components. Have there been any studies as far as what the levels and the various systems should be. Does it look like a food pyramid, for instance? Distribution at the base, static, reactive at the center and the very peak, dynamic reactive. Are there studies, has there been any quantification as far as how the VAR components should be associated and correlated?

MR. HOWE: From our perspective we found many instances the reactive support is most valuable when it is supplied at the distribution level, because that's where you -- rather than at the heart of the transmission system, at the periphery of the transmission system.

MR. MCCLELLAND: That's certainly where it's most efficient also, closer to the load.

MR. HOWE: That's right. The same amount of dynamic VARs if they are located at the periphery where voltage is most at risk can provide. I mean, we did one study where we found that, I guess it's the equivalent of about 18 MVARs throughout a grid was as effective as 100 MVARs of static compensation in the heart of the grid. So, placement, and that's why we think -- for the exact same reasons that there is a lot of interest in distributed generation in order to have more support locally throughout the grid. Likewise there's a similar rational for having distributed VAR support, that the VARs have more value.

MR. MCCLELLAND: So, it may be more efficient from the standpoint of losses through the system because you're not dragging the VARs through the entire system. You are locating them near the source of load, where it's needed the most. And it may be more efficient from the number of capacity facts that you place in service. So, for instance, fixed capacity banks on distribution circuits are relatively simple, and they are also traditional.

MR. O'NEILL: Just to comment on that, you have to look at a 24 hour load cycle or a seasonal load cycle too. More reactive on the distribution may not be beneficial if you get over 100 percent compensation.

MR. MCCLELLAND: I didn't mean to suggest that. From my training it would go back to -- you are probably familiar if you're an engineer to the one-third rule. So, we would use one-third of the distributions first load, place that out on VARs. But we never into the lead. That put us in the lag, however. And if that company needed to supplement that distribution circuit and switch capacitor back. So, I couldn't agree more. And I guess everything in balance.

But my question is more to the point, has anyone seen a correlation? And this was probably bring the days of the vertically integrated utility where distribution transmission generation were all bundled together. Studies were conducted and a split or determination of the levels and the amount VARs were put in place for reliability purposes. Is anyone conducting such studies today? Is anyone trying to quantify the amount of VARs we have in place. What the needs are? What the most efficient needs, a way to supply the needs would be? Is there anything like that, Professor?

MR. BOSE: There are a lot of studies going on how voltage and VARs and the relationship between them. But I thought you were asking for specific studies in specific areas. The one thing thought I've heard from a lot of the operators and I hate to speak for them, since they're all here. This whole concept is all going back to engineering type outlook, where you essentially set power factors for notes. And if it is a distribution note, then they have to manage that power factor between a certain level. That certainly brings down, at least on the static VARs area what you need to produce on a day-to-day basis. So, it goes back to my comment, there's many ways to skin the cat as to how you are going to look at the market place or how are you going to compensate it. That is, if you plan the things right, then you will probably decrease a lot of your requirements, in terms of dynamic VAR requirements and the day-to-day requirements or the hourly requirements so to speak.

MR. MCCLELLAND: And I didn't mean to belabor that question, but it's a lead into the next question. Mike, something you said intrigued me. And I've heard it several times, several times by the panelist. Is that within the urban areas generation supplies are retiring, for whatever reasons, market pressure, emissions issues, EPA regulations, et cetera.

But as the urban areas are retiring generation, and as we are transporting power further and further distances, and reactive power supplies becomes an issue of great concern. Now, I don't mean to put words in Eric's mouth, or certainly, John's, but one of the things that I've heard was that FACTS devices can be a solution for the VAR support. What about for the generation support itself, is that a partial solution? Is that an entire solution? What is your perspective on that?

MR. CONNOLLY: In our situation, and looking at the studies that we've done, and the various resources that might be available, I guess the answer is that there are really three possible ways to address that. One of them is to increase the capability of the existing generating facilities. Another one, is to install FACTS devices and VAR capacitor banks for steady state. I tend to think more about the problem with dynamics.

The other things is to install transmission improvements, where additional transmission lines that basically reduce losses in the system for supplying the reactive from the point of production to the point of consumption. So, all of those are possibilities. Certainly, the transmission improvements are generally going to be building a new line, and generally going to be the most problematic and the most expensive. So, you come back, in our minds anyway, to the compensation and capacity banks with FACTS devices or some type of system of compensating generators to improve the performance of the existing generation facilities that are out there.

MR. MCCLELLAND: What about instead of retiring the old generators, what about conversion to synchronous condensers?

MR. CONNOLLY: That's certainly a possibility. And again, there are economic trade-offs involved that have to be considered. But technically that's certainly a viable solution.

MR. HOWE: It would certainly address the fuel supply and emissions issues that we've seen in urban areas. It may not prevent the local mayor from wanting to reclaim that area as a ball field or a park.

MR. MCCLELLAND: Right. But it certainly may help as far as VAR support.

MR. HOWE: I think it's important to state, just for the record, I would not suggest that dynamic VAR support in an urban area is a -- it's not a full and adequate substitute for having the -- you need the thermal resources, either generating capacity or you're going to need to find ways to get more transmission into those areas.

MR. MCCLELLAND: If I could just stop you there for a second, because I want to highlight that point. It is becoming increasingly difficult to build transmission into urban areas. The corridors aren't readily available, and siting issues have always been a serious concern. And it seems like every day that passes they become more of a concern. So, yeah, I just want --

MR. HOWE: Actually, have us back in a few years as we make progress with superconductor cable. One of the advantages that that cable will offer is very low voltage drop. Because of the inherent design of the cable, it will make it possible to deliver power, you know, 30 to 40 miles from outside of a city to the -- into the bus VAR in the city, and have it appear as if it were only two or three miles from the city, and really provide stiffer voltage.

But to the extent that you over compensate, you run the risk -- you basically can precipitate voltage collapse if you have too much compensation. Because you can prop the voltage up, but then you hit the cliff where you drop off, and we have to avoid that problem.

MR. MCCLELLAND: Thank you, Mike. I don't want take all the time, if we've got some other questions. But to me the reliability aspects are interesting.

Mike, what is the coordination for the New York ISO, what sort of coordination is done with the distribution folks under the transmission operators? And are you satisfied are as close to unity power factor is set?

MR. CALIMANO: It is an interesting turn of events and operating the transmission system because one of the things in any transmission operator under a rate freeze has in construction projects is to cut back on expenses, and distribution reinforcements are probably in that category, coming from a utility --

MR. MCCLELLAND: Capacitor banks aren't very expensive for distribution services.

MR. CALIMANO: Use of the transmission system for either transfers across the system or for support of local areas is the question that we have on the table now going forward on it. And one of the questions, and it probably gets into the short-term benefits of the system is that you reinforce the transmission system to increase transfers, whose the beneficiary of that. That's not necessarily the person that's putting in the capacitors.

We're trying to establish, what I think New England is a lot further along that, establishing zones, reactive supply to effectuate, because the more system reactive, the less transfer capability hits the system. And New York is voltage constrained on a number of interfaces, and in a number of cases we have that situation. And it's a difference between modeling between the planners and the operators, what system they have. What they expect the system to operate at and what it does operate at from power factor point of view, issues are less also.

We haven't come to the conclusion if you do put a 200 mega VAR capacitor bank on a volt power system, what's it doing the MVARs for? Maintain or increase transfers to support the local area.

MR. MCCLELLAND: And as far coordination with distribution circuits, are the distribution providers, it's spotty at best, would you say?

MR. CALIMANO: Right. We maintain voltage schedules across the state for that. But the reinforcements are -- access to those things are the things that we have questions about.

MR. MCCLELLAND: How do you decide you decide on what the voltage schedule should be?

MR. CALIMANO: We do extensive voltage transfer calculations. Being voltage constrained to do a lot of them. And we try to maintain a transfer level.

From that, we can create what kind of voltages we need across the bulk system to maintain those transfer levels. And we allow upwards of maybe a five kV drop on a 345 kV system following any contingencies. So, there are guidelines that we have in there.

MR. O'NEILL: Do I understand right, you try to send out a voltage schedule?

MR. CALIMANO: We have an established desired voltage range for the system.

MR. MCCLELLAND: Are the generators allowed to produce within that range? Or do you send them schedules that they have to adhere to?

MR. CALIMANO: No, they are allowed to produce within that range. If we seem to have a voltage issue, we'll ask for more reactive support.

MR. MCCLELLAND: Do they have any idea where they should be in that range?

MR. CALIMANO: Generally, it's interconnected, so it's not really too much arbitrary. But we try to stay in the middle of that range. Like I said before, there are some cases where we have high voltage contingencies and some cases where we have low voltage contingencies. So, sometime you have to run-in --

MR. MCCLELLAND: What I'm trying to say is, when you're within the voltage contingencies where the reliability is met, there's now a range in which you can operate which changes the economics of the dispatch. Do people understand where they should be in that range?

MR. CALIMANO: I'm not so sure that I have much difference in the economics dispatch when we get to that. They operate in the middle -- generally in the middle of the range.

MR. MCCLELLAND: Mr. Federo testified that you can get 800 megawatts with a little bit of reactive power from Quebec. That would probably be quite an economic undertaking, I would assume. Right?

MR. CALIMANO: I imagine that would be. And again, that is to ensure bigger delivery from the north requires you to put reactive devices in the south. So, we get into the compensation issue, and the cost of who does what.

MR. MCCLELLAND: Certainly, the person whose is going to input it, may be willing to take it without a reactive power device. So, it doesn't have to --

MR. O'NEILL: Kevin.

MR. KELLY: I was interested in asking the panel a process question of how we move forward. One of FERC's interests is in addressing the question of compensation for reactive power. And yet many of the panelists said we need new standards. Mr. Fedora said we need interconnection standards for merchant transmission. Mr. Connolly said we need to extend the low voltage right-threw to all generator. Transmission systems should have standards to be more resilient themselves to voltage support so they don't trip generators. You also emphasized the need for more transient stability standards, shorter recovery times. And other panelists called for standards, too.

The question is this, two part question really. One is: how do we go about getting those standards? Should NERC be charged with doing this? Are some of these areas where FERC should have the lead? That's part one of the question. And what should be the role of RTOs in non-RTO areas?

The second part of the question is, do we need those standards to move forward on the compensation, two meanings, reactive power compensation, and money compensation. To move forward on the money compensation at issue, are there existing standards, although they could be improved, that are adequate to allow us to begin developing a compensation clause.

So, first, who should develop standards? And what should FERC do in the meantime?

MR. FEDORA: I was going to mention on the first part of this, NERC does have a standards authorization process that anyone that is a stakeholder within the North American interconnection can propose standards. And there's several standards that run the gambit from, requirement of support of a nuclear power plant, back-up/standby generation with grid back-up, to resource adequacy with diversity in fuel supply.

MR. KELLY: Phil and Kevin --

MR. FEDORA: Please.

MR. KELLY: I think all the panelists here are very familiar with that process, or all of the FERC people, so I'm not sure if it would best use of our time to walk through that again. We have heard -- John's probably made the presentation at least four times around this table. I just wonder if we could focus more on who should develop reactive power standards. Is it being done now? And role should FERC play? And can FERC move forward on money compensation issues without those standards having been perfected?

MR. BENJAMIN: I think NERC plays a pretty important in this area. As a result of the blackout investigations, both our planning and operating committees are looking at the need for additional standards. And I guess a couple of thoughts here. Generally, the philosophy in writing NERC standards over my career would be organization has been that the standards tend to be performance based. In other words, the standard would say, well, a transmission operator has to maintain its voltage within established limits. I mean, that's one way to write a standard. And that way Mike Calimano could say, okay, here are the established limits that we're going to operate within the New York ISO system. And so the NERC standard would say, transmission operator you have to operate within those limits.

And those kinds of debates as to how prescriptive the NERC standard is, takes place within our committees and within the industry. So, it's difficult to say well, NERC needs to have a standard on this or a standard on that. But what I would say is, that I think it's very critical that those debates take place within the NERC community. And I think within the technical committees that we have established, that Mike participates in, and others participate in, and others participate in, that they bring those issues to the tables, so that they can get into those debates. And then if one of the committees feels that there needs to be a standard, or one of its subcommittees, then as Phil said, there's a process to go through.

So, I can only give you a general answer. And that's that NERC needs to continue talking about these things. The second question that you asked has to do with the relationship, I guess, it has to do with, what can the Commission do? And there, I think we get into the difference between having either NERC or regional or ISO standards, versus something in an interconnection group. And the trade-offs of one versus the other.

Now, generally speaking, there's a lot of merit in having those standards, not in the interconnection agreements, but in the standards, because those are the things that get -- they get debated publicly. And as, I think, some of the comments we just made with respect to Wind generators, in that appendix, it's in there. It was NERC's opinion that rather than having standards in that interconnection agreement in that appendix, those standards ought to be NERC standards, regional standards, et cetera.

So, generally speaking, that's what I would suggest, is that we concentrate on standards that we can right within the standard setting community within the industry NERC regions, et cetera.

And the third question you asked, I think had to do more with compensation, monitoring compensation. And I don't think I'm good expert to talk about that. So, I'll let someone else address that issue.

MR. BOSE: I don't want to get into the

question of who should write the standard. But there are obviously some standards by the operators in doing all their studies that sets voltages and so on and so forth.

I think where, probably, standards are not existing, are in the area of voltage control itself. If you think of frequency control, NERC has very, very tight standards on frequency control. If you look at the voltage control part, it doesn't have that tight of standards, or a monitoring process. And so maybe there is room there.

I would suggest only on the compensation question, that if you look at it from the reliability viewpoint, 90 percent of the problem is in terms of what equipment you need in terms of VAR support on the system. So, I think it brings us right back to the questions that people AEP and John Howe raised, that most of it has to do with the cost of having -- the capital cost of putting the equipment in, whether it be FACTS devices or -- and without those you are not going to be able to handle those few instances where you're going to have the fast voltage support needs. And that doesn't need a spot market, so to speak. I mean, it needs the same kind of incentive that you're struggling with in terms of new transmission.

I mean, what knew FACTS devices do you need on the system is the question.

MR. SINGH: Is that really true though? Because I think a lot of speakers emphasized that you've got pay for capability. It's capability that's more important here, unlike real power.

When I think of the example of load pockets, and that's the example that John referred to, and it's in the report. I think things are a little bit different there. It's not necessarily just a few milliseconds. You are producing support for a generator, operating at load for many hours, creating additional import capability into the load pocket. And I'm just wondering, is that something different from just having the capability. Because that would be an example, as I see it, more of actual production or VARs, be it from a generator or be it from something else. So, I don't know if Anjan or John wants to --

MR. HOWE: Well, actually, I mean to cite one example of one of our insulations in Southwest Connecticut, we were have three of DVAR devices, they sit there at there at the ready. But they are not providing reactive on a constant basis. But their presence there allows ISO New England to up rate the line going down Southwest Connecticut, I believe it's approximately 100 megawatts. So, I think there are instances where the mere presences, passive presence of dynamic reactive support allows the system to be operated closer to its full thermal potential. And if you are only compensating on the basis when these dynamic reactive devices fire, you're not going to come close --

MR. O'NEILL: Is that because you've eliminated a contingency?

MR. HOWE: Exactly.

MR. O'NEILL: So, they are passive in the sense that they are reserves, like real power reserves are reserves sitting there waiting to be fluid. So, in the real power world we would just classify those as reserves.

MR. HOWE: Okay.

MR. O'NEILL: That are there ready to produce reactive power when they are needed. Hang just one second. I think Eric had an additional comment.

MR. JOHN: I think this speaks to the idea of static VARs versus dynamic VARs. And the definition and the way I like to think of dynamic VARs is exactly that. They are an insurance policy. They are standby. They are dynamic in the sense that they are available in the instant when you need them for typically a very short amount of time. And that's for contingency situations, immediately following a contingency situation. And a generator can provide that support locally, provided that it is up and spinning.

A static source, which can also be a generator, is good for steady state voltage control. So, as a line loads up during the course of the day, you could have a generator ramp up its output compensate for the voltage -- the corresponding voltage decline. Similarly, a capacitor bank -- a fixed capacitor bank could also perform that function. So, to me it's like the reserve is a dynamic -- is what a dynamic VAR. It's dynamic in the sense that it is a reserve. It's an insurance policy for the grid.

MR. O'NEILL: We have categories of real reserves, based on how fast they can respond to a contingency. And maybe the time frame is different, but to me, it sounds like it is, essentially, analogous of how you need reactive power devices that can respond in certain time frames. Maybe much faster, but the concept is the same. And we create real power reserves based on how fast they can respond.

MS. CANE: Related to this, one of my questions is, is there a need to make a standard need for -- to define the standard need for reactive reserves the way that we do for real power reserves, but it is clearly defined what is expected to be there?

MR. JOHN: I don't know that, particularly for dynamic reserves, I think it may be more useful, actually to define dynamic voltage recovery, as opposed to what the associated reactive reserve is. I know in the WECC there are standards for voltage recovery, post-fault. And I think that is kind of a -- would be a better way -- a more appropriate way to write a standard on voltage control. Because that is what you are really after. You want the voltage to come back. Who cares how many VARs it takes to do it? You want the voltage to be back to keep your system stable.

MR. O'NEILL: But don't the equations tell you how many VARs you need to get the voltage back?

MR. JOHN: But it depends on what your system looks at the particular time of the contingency. If you have more generation on, you may need for VARs -- you may need more VAR reserve. And if you have less generation on, if you have a weaker system, you don't necessarily need as many VARs to accomplish the same thing.

MR. O'NEILL: Is that a stability issue, or a voltage issue?

MR. JOHN: Is what a --

MR. O'NEILL: What you just described.

MR. BOSE: Can I say that it is a voltage stability issue.

(Laughter)

MR. BOSE: But the point I think Mr. John was trying to make is since the voltage control or the dynamics of the voltage control, there are no strong standards. It's kind of hard to decide exactly what kind of dynamic voltage you need. But there is a difference between the real capacity for controlling frequency, as opposed to VAR capacity. Controlling wholly in the sense that you can tell ahead of time how much capacity you need for that frequency. It's a relatively linear calculation. Whereas you wouldn't know until the VARs, depending on the system, how much VARs you need to control.

MR. O'NEILL: In the back of my mind I keep hearing somebody say, implicit function theory. I mean, is this -- the fact that the response is much more non-linear, or that the implicit function there ain't working for me?

MR. BOSE: I would say, it is non-linear. And it's dependent on all the voltages of the system, the system conditions.

MR. O'NEILL: Isn't the frequency depending on all the generators in the system?

MR. BOSE: Yes, but the approximation is a lot lot easier to figure out. Because finally you have to match --

MR. O'NEILL: The issue is approximation?

MR. BOSE: Yes.

MR. O'NEILL: So, the implicit function theory actually works. It's the approximation to the implicit that we're worried about.

MR. BOSE: That makes it harder.

MR. KELLY: Just to follow-up on Mary's question. In real power, we've talked about having a reserve margin on loads -- proxy for loss of load probability. We often say 18 percent reserve margin is standard. But I think we all know an odd small isolated system on large generator, you have to have enough reserves to fill in for that. And the odd small system may need a 40 percent reserve margin. And yet the concept of a standard for a typical system is useful.

Taking John's answer, what I heard was, well, there is no useful standard for VAR reserves. It's not a useful concept, because every system is different. What you want are standards for voltage recovery or voltage control. And if you have those, you can back off and get from that, for that particular system, whatever reserves you need for VARs.

Is it, just to get the panel's agreement on this, if it is true. Is it the case that it makes no sense to have a national standard reserve requirement for VARs or even a system standard, because it changes constantly over time? That the standard that you need is for voltage recovery, even though for real power, we have a standard for real power reserves, understanding that it is for the typical system, and that the odd system would need a different standard.

MR. CONNOLLY: I'd like to answer yes. What I mean by that, I think that a standard for voltage recovery is probably more universally applicable, than the standard for VAR reserves. And consequently, in terms of implementing that nationwide, or even on a wide area basis, I think it may be more appropriate to look at the dynamic voltage recovery standard.

MR. O'NEILL: Now, how does that translate into the type of equipment you want? You want to have this standard. Now how does the generator figure out what it should, and I think you talked about it earlier, what kind of equipment it should order to get to this standard? I mean, you have to translate that into something -- an order you can send to GE or ABP or something like that to buy the equipment. What do they buy?

MR. CONNOLLY: In terms of the generator capability, certainly one of the key issues for dynamic reactive performance is the way the generator's excitation system responds. And there are a number of decisions they can make in purchasing a generator. And since there are no standards, and there is no compensation for the dynamic reactive capability, the decision that gets made is to buy the least expensive device that's available. So, you end up with something that is inferior in terms of performance to what could be out there.

Now, I don't have a specific recommendation and how to address that in terms of a standard for generator that they would follow in going out and purchasing equipment. I think that is the sort of thing that can be complex and may in itself be the subject of a technical conference.

MR. MCCLELLAND: But it wouldn't be a voltage recovery standard?

MR. HOWE: No, that's completely separate type of issue. It relates, but it's equipment specific type of issue.

MR. MCCLELLAND: Which is a generator rating and then a power type of rating --

MR. HOWE: Exactly.

MR. MCCLELLAND: So although the voltage recovery standard is very appropriate from the standpoint of not establishing a minimum number MVARs for reserve for system operation. From an equipment purchase standpoint, it wouldn't be applicable? You wouldn't walk into GE and say, I need a certain voltage recovery system, because that would be highly system dependent, and it would be dependent upon the circumstances.

MR. HOWE: So, you wouldn't order reactive power capability. You would learn --

MR. MCCLELLAND: You have to transfer one into the other?

MR. HOWE: Right. The capability are built into the generator itself, which is a higher NPA rating, which includes real and reactive power, and then the power factor rating its size. If they system operators had their way, it wouldn't be a typical .95 to 1.05. It may be .85 to 1.15.

MR. O'NEILL: Dave has been waiting patiently.

MR. SHARMA: Dr. Bose, you talked about VAR as a resource, and then you quickly shifted to voltage aspect, because you said that's how you get the VARs, which is true. And lately I've been engaged in this discussion, it seems to me that we're heading towards voltage. My question to you is: Is there some international experience where those countries facing this VAR issue that we are discussing today, that they have really gravitated towards voltage as a solution -- voltage as a problem to address, and VAR is behind it? In other words, once you have confirmed the voltage issue, the VAR would be secondary to that? And do you do the VAR compensation, but really you are controlling the voltage?

MR. BOSE: I don't believe anybody has quite done that. Now several countries have experimented with different kinds of compensation for VARs. And on the other hand, I think Europe has gone a little further in what we call secondary voltage control. So, that not being necessarily connected, because everybody is worrying about two things; the reliability of the system, which you are trying to do by doing tighter voltage control. On the other hand, you have this open issue that Mr. O'Connell mentioned several times that there is a compensation of where the VARs are coming from.

I'm not sure necessarily that anybody has solved the issue, because the issue remains a very difficult one. I just wanted to also point out in something that Mr. Kelly raised about why is it so difficult to figure out what kind of reserves we need in VARs? And the reason it's relatively easy on the real power side, is because you know -- if you know what the load is, you can count on the fact that the losses in the system is bounded in a very small range, three to four percent, two to four percent. So, you can actually calculate with relative accuracy how much reserves you need. Whereas in the VAR, you see the losses range over a very large percentage range over the day, and depending on contingencies, depending on system condition, it is almost impossible to predict ahead of time what kind of reserves you need on the VAR side. And that's been a real problem for the RTOs and the ISOs to try and guess.

MR. SINGH: But there's really two aspects to the reserve analogy. One of them is that when I think on the real power side, I think of seven percent reserves. So, that's not really a standard for generators. It's more -- it's something that's going to give me an idea, what's the size of the market. So, if I'm an investor in VARs, I want to know how VARs is the ISO going to procure? As you point out, it's difficult to translate it into a number, because the standards are in voltage control.

MR. BOSE: Right.

MR. SINGH: And if I take one system or another the number of VARs that I need dynamic or static would be very different. So, maybe you don't have a standard, but you still have sort of more transparent studies, people would get some idea, what's the size of the market.

The flip side of the equation is the standards on the generator itself. So, there we have 10 minute reserves, we have 30 minute reserves, 60 minute reserves. And we have specific guidelines on what equipment a generator needs. And I think we could do some work there on the reactive power side by saying, is it okay to say we have dynamic reserves and static reserves, or do we need to go further and classify those reserves into different response times. Maybe list out, do I need certain equipment installed? Maybe that's an area for further work.

MR. BOSE: And that would solve the question that Mr. O'Neill raised about, what equipment do you order? I mean the manufacturers would certainly like that. If the kind of voltage control is specified a little more clearly, then the RTOs can say this is the kind of response we need. And then you know what to specific, because otherwise you are only talking about capacity and not dynamics.

MR. O'NEILL: We're at 11:15. And even though I think we are just getting started with the discussion, we have run out of time. I would like to thank all of your people for coming. Like I said, I have a list of questions here, and maybe we can continue at future time and date. But I would like to thank you. I think we've started the discussion, we've peaked the issues up. And in the next session I'll confine it to market, since that was a topic that came up a few times. Thank you all very much.

I would like to take a five minute break and let the other panelists set up.

(Brief break.)

(Whereupon, the session was started before the court reporter had returned.)

MR. BETHEL: -- and then we could pursue the voltage controls. Because pricing is my area, and I've been design for quite a while. Intrinsically, a lot of people refer to the way generator supplied voltage support is priced in this country is the AEP method. And it's been a good ten years, but I am going to tell you that it is time to move away from that.

In ERCOT there's a method that we think works pretty well. And it does what I heard a lot of on the first panel saying needs to be recognized. It recognizes performance, and it compensates generators for performing the support voltage. It also compensates in doing that you have to sacrifice megawatts hours service at their lost opportunities.

Basically, the way we see it is that a lot of things have changed since the pay for capability, the generators with reactive capability were designed. That became more or less the cost standard.

In our zone, zones, I should say, AEP has acknowledged in three RTOs. And more than 16,000 megawatts of merchant generation has been constructed just in the last five years. Now, it wasn't constructed necessarily because there was a capacity need to serve a load in our zone. And since we've offered several times that reactive doesn't travel well, in all cases. There can be an excess of reactive in a given area, even though somewhere else is short.

Customers, if they have to pay for the capability, and there is more capability than they need, you can be over charged. Now, some will say that means that we should pay for capability, but we should first determine whether there is a need for the capability. But in a market where generators are encouraged to build to meet needs of their market, rather than go through a process of determining a need to serve others, then we think the paradigm has changed from it was ten years ago. And the pricing for that service, and payment for that service needs to be different.

I'm kind of changing what I was going to say as I go, because of the things I heard. For example, I'm a little nervous. Native load is, of course, going to pay the bill for all of this. If payment is based on capability, and we have heard there's lots of different kinds of capability, that complicates the issue.

But we also heard a lot about FACTS devices, superconducting technology. It is equipment that can be put closer to the load, and support voltage. As generators are generally moving farther from the load. And just what I would say about that is, those kind of devices that are put close the load on the transmission system, on the distribution system, those costs should be built into those rates. And as one person said, receive a salary, not be paid for the number of bullets they expend.

But generators have to be on-line to provide voltage support. And those that are on-line and do that should be paid. Those that don't provide the service, well, some would say they still have to have the capability and I agree with that, as condition to interconnection to the transmission system all generators should have certain capability. And I think that needs to be defined. I heard someone say that we're retiring old generators that have rotating exciters with new ones that static ones, and they don't have the same capability. And it makes me wonder if they should be paid the same. And capability is not a good way to do that, especially if capability conditions, whatever it costs to build what you have.

What we have seen in the new generators that work on our system is that the cost per mega VAR can be several times what is on our own system today. And it can be unusually high. And it has been located in areas where there is already plenty generators by reactive. So, that it's not only excess capability. It's not on-line to provide service, and if you pay for capability you're going to pay for several times more per megawatt.

So, we pursued in the Southwest Power Pool Group where this issue has currently invaded the stakeholder. In the first round it didn't result in a consensus. How to pay generators for (inaudible). We pursued the idea of a needs test for reactive. And pay on the capability that was needed. But we saw how difficult that is to get agreement on. How should we determine need? Some people will say, we'll take all the reactive we can get, you know. The reserves are great. But we've already heard here today that those reserves aren't useful in the transient situation, unless they are on-line. So, we've kind of come around to a different way of looking at this, and decided that if a generator responds to the transmission providers request for service. And yes, the voltage schedule is a standing request by voltage support. But it can also can come into the case of a direct request in real-time to change from that.

If you're not on-line, you can't respond to that. And so, paying all generators that way won't lead to comparable compensation. But paying generators for responding to the voltage schedule and responding to the operator's request to support voltage can.

In fact, I guess, I would call performance the ultimate needs test, as well as the ultimate capability demonstration. So, we would support a method like the ERCOT method, as far as generators are paid per mega VAR hour, but instructed reactive supply where voltage support is broken, plus the cost of any lost megawatts hour sales, or if they are off-line, and they are required by the operator to start up. They should be compensated for that start up where they have provided a minimum amount of energy.

MR. O'NEILL: Thank you. Allen.

MR. MOSHER: Thank you. I'm glad to be here. This is, I have to say from the start, a great report. Interesting, I really enjoyed reading it. But I want to start off with a "Let's keep it simple." Let's not try to launch off in creating complicated market design that's not commensurate with the underlying problem that we've got here, at least not until we get a better handle on the engineering problem.

MR. O'NEILL: Could you turn on your microphone?

MR. MOSHER: I'm sorry. I forget to flip it on. I'm Allen Mosher from the American Public Power Association. I represent municipal and state owned electric utilities. We own small portion of state owned transmission grid. We're generally transmission dependent utilities. We buy a lot more energy than we generate.

I come at this from the perspective of load. And I'm urging the Commission on balance to try to keep the solutions you come up on the reactive power problem as simple as you can, at least at the start until we get a better understanding of the engineering considerations involved.

Let's start off with the issue of standards that Kevin raised, and I think summarized. We don't have good industry standards yet for what the outcome we want, at least not ones that I think you should take and enforce here at FERC, to say that somebody wasn't in compliance.

Let's break it down into the pieces here. I hope that we have standards in the future that say that generators need to perform in a particular way to inject power into the grid. But they would inject it within some narrow power factor range, so they don't impose a burden on the grid.

Loads similarly need to have a power factor that keeps their reactive demands within in some narrow range. If we do that, then we are going to reduce the size of the problem. And we can then focus on what is the outcome? What kind of standards we need on the bulk power grid; or that is, what is the outcome that transmission providers or system operators need to produce? Once we figure out those standards, then we can back up a bit and say, what are the sources for the different kinds of reactive capability that we need. We've talked about the static sources, it's covered extensively in your report. And we are talking about dynamic sources. And as we said earlier this morning, there's a major premium in value on the grid to have dynamic capability in the right location on the grid. It performs a number of different functions.

It allows you to increase your transfer capability. If you know you have that dynamic support there you can sell more transmission service. And it also allows you to recover from contingencies. When you lose a generator, when you lose a line, if you've got that dynamic capability there it responds quickly, we can do more with consistent (inaudible.)

In the future we hope that we will be able to design the grid better. And by that, actually I mean the bulk power system, which includes generators, all the devices that are hooked up, so we can keep costs down for consumers. But I am still not convinced that this is a problem that needs a spot market for reactive power supply. I think the complexity of that would overwhelm and benefits from that. Maybe I'm wrong. But it doesn't seem apparent to me right now.

I guess to the next one. What's the simple method that we can use now? I agree with Dennis that the AEP Method is broken. That just taking the book costs of generators and coming up with a formula, it was a good proxy when we started out with this process with Order 888. I was on staff when you were doing this kind of work. We had to come up with a reasonable number.

We had to come up with something to compensate transmission providers who were using their affiliated generation to provide reactive power support to the grid.

And the AEP Method is one such method. But it is like transmission rates, it's a stop clock. It's right twice a day, the rest of the time it's wrong. It's not here to overcompensate. It under compensates generators. In the longer term, you probably ought to be looking, as has been suggested, to something more in terms of capability, some kind of charge for capability, and then compensation for what you actually produce. And you definitely need to have the generator testing as part of this process for all reactive sources to make sure that they actually provide what is requested by the system operator.

The big risk we have right now, is that because we don't how much we need and where we need it, we are going to end up passing out checks to people who are, basically, not providing the capability that we need. If we had a 50 percent reserve margin for real power capacity in the region, you would go out and say, we ought to buy all of that. We would plug in only by 15 or 20 percent reserves. The same thing is true with reactive power. We don't need all the power that's out there. But some of it, we need that. You need to have that reactive power in the right location on the grid. I just can't tell you how to get there. And from the first panel, I don't think there is a consensus in the industry.

FERC has a comparability problem. We have to do something. It's not tenable to only take the generators that are affiliated with the transmission provider. Independent power producers that provide reactive power -- to the extent that they provide a comparable supply, that is equally valuable to the system operator, they need to be compensated.

The same thing for load serving entities that have distributed generation close to load. To the extent that you've system conditions where you may have a reactive power problem, they ought to be compensated for reactive power that they inject, again, beyond the power requirements that they have. They extend their tariffs, but rather to the extent that they are supporting the voltage transmission grid.

Let me go back to my notes and make sure I didn't miss anything. I think you can sum it up and say that we would favor forward contract procurement approach, probably with multiple tariff. But again the issue here is that we've got system operators that are going to be preparing these resources. That doesn't look a competitive market, where you've got lots of buyers and lots of sellers.

Thank you.

MR. O'NEILL: Mr. Bertagnolli.

MR. BERTAGNOLLI: I'd like to thank FERC for hosting this technical session of the subject matter industry when it can have a profound impact on reliability. My name is David Bertagnolli. I'm the principle engineer from system operations at ISO New England, the regional transmission operator.

I'm involved in all aspects of transmission operations, including direct power dispatch, transmission needs. I'd also like to compliment the Commission on an excellent report. It provides a very thorough description of the reactive power phenomena.

I'd also like to recognize Mr. Calimano's remarks regarding the New England Bulk Power Compensation program. I'll give a bit more detail on that in a moment.

Keeping reactive power in balance requires coordination between all three sectors of the power system; load, transmission, and generation. For example, it's unreasonable to expect generators to provide all the reactive power needs of the system when a solution at the distribution level would be more appropriate and much more efficient. At the same time, requiring load to achieve perfect power factor at all times is unrealistic. And finally, the transmission system alone simple cannot be expected to balance both the supply and demand efficiently at all times. To ensure reliability bulk power system operations all three aspects must be coordinated.

I would like to describe for you some of the things that we do in New England as a regional transmission organization to balance reactive power needs to maintain reliability while operating an efficient marketplace.

Due to the local nature of reactive power ISO New England oversees an annual process to determine the reactive power burden that load may place on the transmission region, with ten sub-areas in New England. Through this annual review ISO can determine whether there is excessive or insufficient reactive power demand, this allow New England entities such as distribution companies to identify local solutions to local reactive power needs, where such solutions can optimal results. We publish a summary of deficiencies by load company and sub-area, which gives those companies not in compliance the load power factor requirement an idea how much shunt compensation to install and where.

After looking at these local needs on the system, we then have to deal with losses of reactive power on the transmission system. To deal with this the ISO through the regional system planning process identifies transmission based solutions, such as shunt capacitors and StatComs to address basic reactive power needs.

In this fashion generators which provide dynamic reactive power are available to respond to system contingencies when they're most needed. As a result the question of how to compensate generators for the dynamic reactive power capability is an important one. Presently the ISO tariff provides four methods of compensation to generators to address reactive power issues.

Let me take a moment to identify these at a high level. First, payment is provided for energy consumed as a result of running a hydro or pump, or combustion turbine generator as a synchronous condenser. Second, lost opportunity costs are compensated when a generators real power is reduced so that it may provide reactive power.

Third, energy cost is compensated when a generator is run to provide high voltage control. And fourth, the basic reactive power producing capability is compensated through an annual payment of, approximately, $1000 per mega VAR lagging capability to those generators that meet the filing and testing requirements, regardless of their location.

I'd also like to note that New England is currently examining these methods of compensation, and whether other methods are appropriate. For example, the region had been investigating whether non-generator sources of dynamic power such as synchronous condensers or converters, StatComs, or HVDC terminals should also be compensated in our Schedule Two to the ISO tariff.

Again, I would like to thank FERC for hosting this conference, and looking forward to discussion these issues further. I would also not that ISO intends to submit comments on the questions in the Staff report by the deadline.

MR. O'NEILL: Mr. Wofford.

MR. WOFFORD: Good morning. My name is Steve Wofford. I am a vice present of Asset Operation of the Constellation Energy Commodities Group. I would like to thank the Commission for the opportunity to be on the here. This is the first change that I've gotten to sit on the panel. I'd also like to thank the Staff the

White Paper, it's a great resource for all of us to use as we examine this issue.

Over the last five years, I've prepared the technical testimony for five reactive filings. I've assisted in the testimony for a sixth. So, I'm familiar with the AEP methodology. I appreciate the fact that Dennis put that together. I'll point out later, I think, in the short term it is still an appropriate mechanism to use.

I've also participated on a number of PJM working groups and committees. I've participated in a reactive working group, which we put together the '99 low voltage event at PJM. I'm a member of reliability committee. So from a personal perspective I try to examine this from and economic perspective, as well as reliability perspective. And that's the way our company looks at this.

To prepare for this panel, I went back and I looked at some significant events over the last six years and the reports that come out from those events. Those recall reports would indicate that a lack of reactive supply, a lack of reactive reserve is a problem. It's something we need to address. Constellation is considered in the short term, how do we address these issues?

We understand the local nature of reactive power. We understand in putting together a spot market for reactive in the short term is problematic. It is something we should continue to look at, but in the short term we view it as something that is achievable.

Constellation has generation, merchant generation both within ISO footprints, and outside of the ISO footprints. So, we understand the challenges that generators face receiving compensation for reactive supply. Based on discussions we've had internally, Constellation has reached the following conclusions in the short, and we'd like to share them.

All generators should be compensated for the provision of reactive power. In the short term reactive power compensation should be based on capacity payment. It should be based on the design of the generator and the capability of the generator to produce reactive.

Dennis expressed a concern on the AEP Methodology. In the short term, if used appropriately, the AEP Method is a good proxy. It over compensates some, it under compensates others. But on average it is not a bad methodology.

As we talk about capacity payments, we could look at other methodologies that could be simpler. The process for receiving reactive payments is burdensome.

If we could make it simpler for everyone, that would be a good thing. Where real power production is impacted to support reactive, lost opportunity payments should be made. PBJ does that. New England does that. In a system emergency, you don't want your operator to question the economics of the direction. You want him to follow the direction.

Within design and safety limits of the generator, generators should be expected to follow the voltage schedule they are getting. Reactive testing, periodic reactive testing is appropriate if you receive compensation. Due to the local nature of reactive power, a market based system for reactive power is not appropriate at this time. We should continue talking about it. But we shouldn't hold up compensation in the short term while we talk about it.

It's also important to note the cost of reactive supply, versus the total cost of serving load. In 2003 the cost of reactive supply in the PJM footprint is .52 percent of the total cost to serve load. We need to balance the cost of implanting a market where the benefits of implementing that market.

Constellation is a great fan of markets. We serve 28,000 megawatts of load. We also try to be practical. In some cases markets aren't what you need.

You need a capacity based payment system.

Finally, as with any regulatory change, we need to understand and address existing arrangements that are in place. Thank you.

MR. O'NEILL: Thank you. Mr. Lucas.

MR. LUCAS: Good morning. I am John Lucas here on behalf of Southern Companies this morning and we certainly appreciate the opportunity to speak Commission and staff.

The Staff's report of February 4th noted a number of issues and concerns. Many of those concerns identified in the Staff paper vary across the different regions or markets. As the Commission moves ahead and considers any changes to the reactive policies, and reactive support Southern Companies would hope that we have flexibility provided for the different circumstances that are present in various regions, markets, and in area where RTOs are formed, and in areas where they have not.

Today I will talk from the standpoint of a transmission provider that is not part of RTO. Starting with the issue of comparable service, I guess, I'll differ from some of the other panelists. But our view is, once you are interconnected and synchronized to the grid, all generation sources need to be able to maintain a voltage schedule in order to support the reliability of the system.

The whole purpose in a generator following the voltage schedule is to coordinate the operation of that generator, with the actions and responsibilities of the transmission provider in trying to maintain system reliability. The action of merely following a voltage schedule by both independent generators and those of a transmission provider does not necessarily translate to comparable support of the reactive needs on the grid. I'll give you an example. For wholesale transmission service offering, the transmission provider is required, he doesn't have an option. He's required to provide reactive support throughout his system to support the transmission service.

And independent generator may or may not have a requirement to be generating on a given day. When he is operating, the generator is only a dynamic source of reactive in the local area where the generator is located, not throughout the system. In summary then, one provider, one entity rather, the provider has an obligation, and he's got to support voltage through the entire system. The other entity has an option, and he only contributes in a local area. In our view, these two should not be deemed to comparable in nature.

Turning now to pricing issues, and I don't want to confuse that with compensation principles. We would hope that the Commission would ensure that any ratemaking policy for reactive is consistent for all generator, whether they are participating in an RTO market, or by non-RTO transmission providers.

If an IPP is allowed a variation of the Opinion 440 Method in setting a reactive charge, we feel like the transmission provider should have that option also. Now to the question of what should be the link between comparability and compensation. When a transmission provider determines a need, and that's important, we think it's an obligation for the provider to determine the need reactive control in certain locations on the system. It should establish non-discriminatory arrangements with the generators that are available to provide the reactive support needed, and to receive compensation for that support.

The conditions should cover three areas in those arrangements. One, it should be a long term arrangements. I think at least a year or longer, so that the provider can incorporate that resource into its planning process.

The second part, the metrics should outlined in that agreement that are used to measure the reactive supply of the generator. And last, it should be controllable by the transmission provider for the purpose of supplying the reactive needs on the system; and that would include both day-ahead commitment, and real-time deployment.

And I guess as a threshold compensation issues and being a vertically integrated provider, we're troubled, and would think that all generators, with respect to compensation should look first to their power supply arrangements to recover the costs of the reactive power, and what we will call their cost of reliability responsibility for the generator components that actually reactive power. And I would say that that should be done in a similar manner, as many transmission providers the costs, those types of costs from native load customers, not under a tariff service agreement today.

So, in summary, I'll cover three points. Interconnecting to the grid and following a voltage schedule is required to maintain reliability. That is, the generator should be coordinating the operation of his machine with the responsibilities of the transmission provider. And that action should not automatically be linked to compensation.

Second, any link between comparability and compensation for reactive should recognize the ability of the provider to, number one, include the resource in its long term plans. And two, control the reactive output of such resource. And lastly, the native load customers of the provider should not be left to subsidize any reactive costs IPPs, when they may not receive any benefit from that reactive capability in the location where the IPP is interconnected.

That concludes our comments. I'd be happy to try and answer any question you might have.

MR. O'NEILL: Thank you. Mr. Simpson.

MR. SIMPSON: Good morning. I'm John Simpson. I'm the Director of Transmission Analysis for Reliant Energy. Reliant Energy is an independent power producer with, approximately, 19 megawatts of generation assets located across the United States. In the past year Reliant has filed six reactive power tariff filings for generating plants seeking compensation for the supply of reactive power. Although these filings have been in the context of an RTO with an established process for paying generators for reactive power supply, we are currently working on the development of reactive power tariff filings for other generating plants that are not currently in FERC approved RTOs.

Our initial filings were met with little opposition or questions concerning the appropriateness of the filing or the revenue requirement requested. Comments and interventions were generally limited to being sure all the rules of the RTO had been followed for the generator to receive the compensation sought.

More recently filings have been met with increased opposition, including protests and challenges to what had been, in our opinion, established FERC policy and precedent concerning reactive power tariffs. These challenges and protests raised significant issues that the Commission is appropriately addressing through this proceeding.

In my opinion, the bedrock principle, which the Commission must uphold is that of comparability. Under Order 888 FERC authorized transmission providers to unbundle the provision of generation supplied, ancillary services from the costs of transmission service provided under pro-forma open access transmission tariff.

One of these ancillary services is what is now known as Schedule Two, reactive supply and voltage control service from generation sources. By unbundling this service from the transmission service, transmission providers developed a separate compensation system for reactive supply. This compensation was made to their own or affiliate generation sources since those were the facilities that provided the service. With the onset of independent power producers new generators were connected to the grid and they also provided reactive supply, and voltage control. This brings us to the issue of comparability. These new generators must be compensated for the provision of this service, just as the transmission providers resources are.

All generators provide reactive power and voltage control to the grid. Through the interconnection agreement with the transmission owner the generator operates with its automatic voltage regulator or AVR in the automatic mode. The transmission owner provides a voltage schedule to the generator, which the generator follows with its AVR.

This provision of reactive power and voltage control is priced in three components, but primarily it's a capacity product. It requires a certain capital investment for the generator to provide this service. The Commission routinely allows the use of a levalized revenue requirement for the recovery of these capital costs, and Reliant supports this form of rate design.

The other two components of reactive power pricing could be likened to those of an energy type product. The heating loss component and the lost opportunity cost component are only encountered when the generator is actually producing reactive power, either inside or outside of its comparability curve.

These two components could be priced as energy type commodities, but the fixed comparability component is correctly prices as a capacity product. One final comment concerning the amount of fixed capability to be provided by each generator; the new addition -- the addition of new generation to the grid is a long term capital investment; typically, 25 to 35 years or more. The decision on the amount of reactive supply comparability to be added with each generator or particular location must not be shortsighted so as to create costly reactive power shortages in the future as the grid expands, new loads develop, and other existing generation ages and is ultimately retired.

In other words, I would encourage the Commission to avoid adopting policies that seek to minimize, both the amount of reactive power purchased and the compensation for it, because such policies will likely be penny wise, and pound foolish. The reliability of the system is simply to important to risk.

I, along with others here today, participated on the drafting team that developed the consensus interconnection agreement in the Commission's process leading up the LGIA and LGIP in Order 2003. When we agreed to the requirement of 0.95 power factor for new generators seeking interconnection to the grid, it was understood on the drafting team that this meant .95 power factor at the point of interconnection. That is the high side of the GSU.

However, in order to have a power factor of .95, on the high side of the GSU, the generator must be designed with a minimum power factor of .9 so that after consideration of losses through the GSU, the point of interconnection still has a minimum power factor of .95.

As the policy established in the AEP case, and Opinion 440 correctly recognizes the generator is appropriately paid on the basis of the capability it must installed in order to deliver the desired capability to the grid. Under the LGIA, therefore, on a going forward basis, the appropriate power factor for compensation at a minimum is 0.9.

Reliant believes that Commission's AEP policy is appropriate, as it will allow the Commission to create a reliable system, while also providing comparable treatment to all generators.

Thank you for the opportunity to participate in this technical conference and I look forward to answering your questions.

MR. O'NEILL: Thank you. Mr. Helyer.

MR. HELYER: Good morning. I am with Tenaska. Like John, we're an IPP that owns thousands of megawatts of generation around the country.

As the first panel alluded to, I question whether talking about reactive power is what ought be thinking about, and whether it is voltage control as a service. Voltage control is an essential element of operating a transmission system. Every generator is required to follow a voltage schedule that it is give by the transmission provider. It is -- voltage control is a service that generators and transmission providers alike should be compensated in providing. All of do it. All of us should be fairly compensated.

In order for us to meet our requirements, we produce or absorb reactive power. That's a technical issue that you all heard about earlier, and we won't belabor the discussion with it anymore. No generator, whether it is affiliate or non-affiliate wants to see the lights go off. But all of us want to be treated fairly.

We want to do our job. We want to control the voltage and maintain reliability on the grid. But that does come at a cost. Through every agreement that we have, there's requirements put on us to provide a certain amount of reactive power under various conditions. That is a cost that we incur. It is something, again, that is not negotiable. There are standards that are out there today that require us to maintain voltage schedules; that require us to have power factor limits on our machines. And as a result we ought to be working on compensation, as we've already done in the past, we ought to continue to work on compensation methodologies because we already those standards.

Compensation should consist of fixed costs, variable costs, lost opportunity costs. The fixed costs are a requirement because of the standards and rules and agreements that we all have out there. The variable costs are a result of actually producing it when we're asked to produce it. The lost opportunity costs, I mean, anytime you have an emergency, and if we need to do something that results in backing off schedules or even increasing schedules, or doing something that was not what was currently planned, there ought to compensation for dealing with that issue.

It has been suggested that generators be on-line in order to be paid. I point out that there are lots capacitors, lots of reactors that are out there today on the transmission system that are in the rates, that are not always on-line and cannot always be turned on-line immediately because of the way that they are switched onto the system. But they are in the rates of the transmission providers.

Affiliated generators have their costs included various forms, including Schedule Two of the OATT and other types of rates. And what we feel is that we ought be treated in a similar fashion, in the way that affiliate generators are treated.

With that, I think I would go ahead and stop and let the panel start asking questions. I think anything else that I would say at this point is probably going to be duplicative of what you have already heard.

MR. O'NEILL: Thank you, panel, and I will ask the first question of Mr. Lucas.

Do you use the AEP Method for Schedule Two compensation?

MR. LUCAS: Yes, it is primarily the AEP Method. There are some variations that we proposed in our original tariff filing. The ultimate rate for Schedule Two in our tariff, however, was the result of a settlement that included both the transmission rate, reactive charge, and the scheduling charge. So, it's hard for me to say what pieces of the AEP Method we actually were able to end up with in that rate or not. But it was based on that when it was filed.

MR. O'NEILL: Your reactive power capability has never gone through a needs determination here at the Commission?

MR. LUCAS: That would probably be fair, yeah.

MR. O'NEILL: Do you want the IPPs to go through a need determination before they get --

MR. LUCAS: When you say "need determination" let me make sure I understand what you're talking about. In terms of, do we have the capability in our machines to provide the service we're getting paid for? Is that what you mean?

MR. O'NEILL: You can define it. Is that the way you want to define it?

MR. LUCAS: No. That's not the way -- I thought you were going toward my reactive rate.

MR. O'NEILL: You raised need. What did you mean by it?

MR. LUCAS: Well, I was just asking you a question in terms of what you meant by it.

MR. O'NEILL: I want to know what you meant by it.

MR. LUCAS: Let me answer by saying this, our reactive charge has been through the scrutiny of a FERC filing, and it was the subject of a settlement proceeding regarding our original transmission tariff. So, I would say, yes, our rate has been reviewed by the Commission as applicable to, and just and reasonable for Schedule Two under our tariff.

MR. O'NEILL: But nobody looked at the need for the reactive power that you are being compensated for?

MR. LUCAS: No, other than the transmission provider maintaining our responsibility.

MR. O'NEILL: Should we go back and look at that.

MR. LUCAS: The Commission is open to look at whatever it needs to. We have done a good job maintaining reliability in system, and we thing our reactive support from our system is applicable.

MR. SINGH: Let me follow-up on that point. You said that there should be comparable treatment for all generators; then you also talked about transmission providers versus independent generators. So, I think maybe it makes more sense to look at comparability between generators, rather than a transmission provider versus a generator, which are really different entities. You also made an interesting point about native load customers not subsidizing independent suppliers. But then if we look at the flipside of that, all transmission customers are paying certain charge for reactive power. And these are native customers, and certainly, non-utility customers as well. So, the question is, where does that money go? Does a part of that money go to support utility generators that are providing the reactive power service? If so, would that not be reverse subsidy? And would that not be inconsistent with comparability that you said you seek for all generators?

MR. LUCAS: I don't think so. Let me do part two of your question, because I think I was closer to following that end of it. As a vertically integrated transmission provider in developing our Schedule Two, all of the assets that we used to develop that rate, and again, that rate is only applied to wholesale transmission service, which only makes up about 15 percent of transmission we provide off of the system. But the core investment was predominately already in the rate-base for native load customers. It's there. We had to provide reactive support throughout the system to be able to deliver the generation to the load. So, it's probably paid for the load.

In developing the Schedule Two charge it's per unitized over the entire load of the system, but that revenue is treated as a credit to those native load customers.

MR. SINGH: I guess my point was it is not necessarily just capacitors and transmission equipment. It is also generators using some cost allocation methodology that contribute to the development of that charge, and that's where Dick was coming from.

MR. LUCAS: The transmission elements are in the transmission rate. The Schedule Two is only the generator related reactive components.

MR. SINGH: So, I would still sort of you wonder what is exactly comparable? Would it really comparable to pay some generators and not others? But I think maybe we will leave that for further discussion.

MR. SIMPSON: Can I add something -- a little bit more comparability as far as the rates, since it's been brought up here. John -- comparable treatment to all generators, right now, is provided in Order 2003. It says in the interconnection rule says that if the transmission provider pays his own generator he must pay the others.

Another way for a transmission provider to avoid comparability is to not charge for Schedule Two. And there some transmission providers in the country who don't have a Schedule Two charge.

Now, as John pointed out, the base components of your generation rate is already fully recovered in the retail rates. They only separated out a small piece of that to put in the wholesale rate. Well, to avoid having to deal with wholesale generators, independent generators just don't have a Schedule Two charge. Under Order 2003, you don't have to pay the IPP generators on your system. Again, that's not comparable treatment. If the Commission is going to fix the comparability, issue it needs to look at all transmission providers, not just the ones in RTOs, or not just the ones with Schedule Two charges.

MR. O'NEILL: Thank you.

MR. FINA: Getting down to the nuts and bolts of the AEP Method, are there specific variable costs that are currently not included in the Commission's analysis?

MR. SIMPSON: Are you asking --

MR. FINA: Yeah, anyone.

MR. BETHEL: Variable costs are a very small part of the revenue identified by the AEP method, and they really only occur if you operate the exciter system and cause the generator to produce or absorb VARs. But I have seen in some cases variable cost component included in cost of service proposals by generators that don't have a demonstrated record of operating.

MR. O'NEILL: In terms of variable costs, one of the variable costs would be a request the generator off its real power schedule. In that case, would the 888 Tariff compensate for those variable costs?

MR. BETHEL: The AEP Method puts nothing for that, no.

MR. O'NEILL: Should it?

MR. BETHEL: Should it? Well, I would say that we shouldn't use that method any longer.

(Laughter.)

MR. BETHEL: If you want to try to fix it, first there would be several things you would have to do. Number one, if you're pay generators for the reactive capability, as far as I'm concerned, they should be available. So, then if they have to start up, and you have already paid them for the capability, start-up costs should out of pocket. You know, if you buy a car, you can go out in the garage in it and drive it away. You've paid for it. If you want to rent a car from an agency, you know, then they will have to bring it over and you will have to wait.

It's a different thing to have paid in advance to use something, than to pay as you go. So, if you are going to use the AEP Method, then the units should be able to provide reactive without you having to pay additional charges to get that reactive. Under the AEP Method, are generators, and I guess others have used it, were never paid to start up.

MR. O'NEILL: When you were under the 888 FERC Tariff, when you started your up, did you pass those fuel costs through in your fuel adjustment charge?

MR. BETHEL: I'm sure they are charged to someone, to the extent that they can be. But they are not charged to transmission customers.

MR. O'NEILL: But there is a fuel adjustment charge?

MR. BETHEL: If they have a fuel adjustment charge.

MR. O'NEILL: So they are compensated for starting up?

MR. BETHEL: They're almost always on-line.

MR. MCCLELLAND: The scenario he gave is if you have to start-up, you shouldn't have to pay the cost of starting up. And I would think that most fuel adjustment charges pay the fuel costs of starting up.

MR. BETHEL: They're started up to provide real power.

MR. MOSHER: And the independent powers producers aren't started up?

MR. BETHEL: I mean, I don't know. If they're not on-line, and you need them for reactive, but you have already paid for their reactive capability, it seems to me that it should be there. There shouldn't be additional charges to get that capability. After all, it's an ancillary service. The gentleman from Southern in that regard, you don't expect your -- (inaudible) to be getting most of the costs. This is an ancillary service that the Commission required those utilities that owned transmission to provide. So, they also guided us to a way to break out the cost of that through their instructions to Northern State Power.

MR. MOSHER: To go back real power, you get paid as a reserve and you are called upon to start up, most of the ISOs compensate for starting up. So, you've been paid for your reactive power reserve and then you are asked to start up, wouldn't the analogy be that you would be paid for starting up?

MR. BETHEL: You mentioned something I heard in several other cases. You keep talking about reactive power reserves, but I don't know how valuable those are to the system if they are not on-line. I tend to think of a generator that's off line and has to start on its own, as being provided -- as being capable of providing black-start service. And I don't think we should be confusing black-start capability with reactive reserve capability.

MR. SINGH: Maybe a better analogy there would be with capacity payment, not with reserve, because I think your concern is availability. So, on the real power side, if I'm paying a capacity payment to a generator, there are ways to address your concern. For example, we have the construct of unforced capacity. So, that sort of makes sure that the people who are being paid, are actually available.

I think it is Allen's question that is more difficult to address. You are saying, Allen, how do I know that I'm not paying for too much? I don't pay every generator for operating reserves. I only buy X percent and on the reactive power side, it's very difficult to know what the mega VAR needs are for a system just because of the complexity of voltage control criteria. So, that's, I think a valid point. But it doesn't mean that you don't pay any money.

MR. WOFFORD: That is the core of the problem. We don't know how much we need right now, generator supplied reactive power. It's an input to the system operator reliably operating the system and getting the maximum threw-flow, but we need to secure it in the right locations. And yes, generators incur start up costs because they are called to start up to provide reactive support -- for transmission or because there is contingency or you think there is going contingency. Sometimes you know a generator is going to go down, so you may need to start up one in advance. There might be rare circumstances where you call on ITP, or you call on a utility owned generator to start up, and that ought to be billed. But it's a complexity issue here. I mean that rare and unusual circumstance. It doesn't happen often enough that you want to build rate design around that circumstance. And that's really an empirical question. I mean, years ago I did beta requests, and said, tell me when do you -- a Co-op maybe called on a generator to start up to provide reactive support and the company in particular didn't come back with an answer -- or demonstrate that they actually had done something. The generators were already on-line in that case.

MR. BERTAGNOLLI: But wouldn't it be easier to put the compensation method in? Say, look, we will compensate you for your costs if, in fact, we have to call you up to have you run for reactive power, rather than having no compensation at all?

MR. O'NEILL: Good rate. Yeah, I mean, good rate design should cover those costs. And you should --

MR. BERTAGNOLLI: Even if it's an unusual event you should have the power there to compensate if that occurs.

MR. KUECK: I'm just being practical thinking, do we want to say all tariffs; all generator interconnection agreements have to come in to have this particular clause, provide for this compensation. How do you do it --

MR. MOSHER: How much simpler could it be than to require opportunity cost payments if the system operator asks the generator to back down its real power to supply reactive power?

MR. BERTAGNOLLI: Just getting the clause in place to document the costs and all that is needed. It isn't just a no-brainer. And I agree it's not complicated.

MR. KUECK: You document the costs ex-post.

MR. BERTAGNOLLI: That's what I just said. I said I didn't think it was no-brainer.

MR. MOSHER: Just try to keep it simple. If I heard David correctly, ISO New England studies the split between the static and dynamic needs, and they go to distribution level. So, for the benefit of your members, Allen, how would you know that that investment in dynamic reactive supply was a prudent investment if the distribution circuits hadn't been addressed? In other words, ancillary charges that you are being assessed, through the transmission tariff as a wholesale customer, how do you know that that charge could not have been reduced by the distribution customers themselves supplied their own reactive power needs. And it may be at much lower level and a much more efficient placing.

Every engineer I've talked to has says it's cheaper to do it closer to the load.

MR. MCCLELLAND: Absolutely, and do it at the load distribution. The question that I have for you, from your members' perspective, which is the customer's perspective; are you satisfied that, and you know, it goes across ISO New England's efforts, and how they integrated the pieces to make certain each of those pieces have been satisfied? Are you satisfied from APPA perspective that the ISOs or the transmission operators in the case of, let's say Southern Company, which is non-ISO, that this process is taking place to protect your membership?

MR. MOSHER: I can't honestly say. I've not done enough checking with different members on are they satisfied with the methodology that you use in each region to say that it's -- the ISOs are procuring the right amount. My more general point was that it's -- you are depending upon the system operators to procure the right amount, not too much, not too little. And those who don't actually pay the bills may have a different calculus on what is too much versus too little as to my members.

MR. MCCLELLAND: Is it so small of a charge, Allen, relatively speaking, reactive power charges are not a large charge? Is it so small of a charge that perhaps it just hasn't been focused on?

MR. MOSHER: To date, I think that is true. And my concern is that it will become a major charge. That it won't be -- I think it was said for PJM or ISO New England, New York. It's like .52 percent of total delivered power supply cost. Not a lot to get excited about. If it becomes two or three percent, then we're going --

MR. MCCLELLAND: And as --

MR. MOSHER: That's the problem that we're seeing with the IPP filings. As new filings come in using the AEP Method, we are seeing charges for single IPPs being a major portion of the total cost being charged by the incumbent transmission provider, which in any case, these charges are going to become substantially more, substantially larger. And that's comparable to the experience I had litigation days, where the charge is as filed were like this, and when you ended up with a settlement in the end, they were down like this, (indicating).

If you end up with a formula that says you get this much of a substantial amount, then we, again, shifting all the money around here, and that could be to the detriment of ratepayers. Or on the hand, we may actually get improved system performance. I can't say.

MR. MCCLELLAND: Then I guess I'll throw this out to the panel for their experience. But as we are seeing generation being retired in the urban area, and the need for VAR support because of the retirement of these units, is the trend -- are we seeing, or can we anticipate an upward trend in VAR charges? And in Southern, I would like you to comment to my question, because are still a vertically integrated. So, do you see the trend being in the urban areas also?

MR. LUCAS: Don't see that much of a trend. We have, however, had circumstances where we turned to a merchant on a case-by-case basis, said system conditions next week, or the next two weeks, we need your unit to run for VAR support. Set in place the arrangement and took care of it that way. I will just make this comment, and I'll let the rest of the panel -- I'm concerned, we jumped quickly to the compensation questions. I'd be in Allen's camp, I think it should be incumbent on the transmission provider or the RTO to assess needs first. Step one, should be assess needs, and if you've got multiple dynamic resources locating in a given area, to me, not all of those resources deserve compensation. The ones that the transmission provider needs should be contracted with.

MR. WOFFORD: I find that interesting. We have a merchant plant that is interconnected with Pinaleck (ph), and we're fortunate that we're in the ISO footprint. But if there was needs test for reactive, I doubt that Pinaleck would say that we need the reactive. We filed a reactive revenue recovery under the Schedule Two provisions during the blackout, the 2003 blackout, we started the unit up. We started up in seven minutes. It provided reactive support both as a generator. We provided reactive support as sync condenser to support the start up. Now what's the value of that resource during that particular point in time? It's a very large number. It's a very large number. Now, what I say is, you shouldn't compensate us at that point in time. You should compensate us on a capacity type payment, as we are receiving. And we have an obligation to do that. And we are happy to do that.

MR. O'NEILL: Steve, when you say it was operating synchronous condenser, do you just mean it wasn't using any fuel?

MR. WOFFORD: That's correct. It was motoring with the system providing VAR support and no look out.

MR. SINGH: And, Steve, the figure that you gave, a .52 percent in PJM, is most of that, or almost all of that in capacity payments?

MR. WOFFORD: I would say most of that is capacity payments.

MR. SINGH: Very little for lost opportunity payments?

MR. WOFFORD: Very little for lost opportunity.

MR. SINGH: What is it in New England, Dave, the cost of compensation for reactive power?

MR. BERTAGNOLLI: of the four components, but by far the largest is the VAR capability payment. And I don't know the exact number. It's 10 to 15 million dollars a year. Compensating for the first part, for running the synchronous condensers, provide their losses, very, very small. I should also point, the third part I mentioned, compensating generators for high voltage control, that's probably the largest. At least last year in just one area, we racked up over $60 million payment to generators for high voltage control because of the cost of the energy we had to buy, which was almost out Merit, so that they can absorb reactive power.

MR. O'NEILL: So, you were backing them down, buying other power.

MR. BERTAGNOLLI: We were forcing them on-line to control high voltage, to absorb the power.

MR. O'NEILL: Oh, you were pushing them, so you had to buy their power, so to speak.

MR. BERTAGNOLLI: And that is the biggest payment, second biggest in VAR capability. The other two are very slight.

MR. KUECK: If we could get back to the policeman analogy, which you mentioned just briefly about devices close to the load --

MR. MCCLELLAND: John, I hate to interrupt, but I think we had one further comment from John Simpson.

MR. KUECK: Sure.

MR. SIMPSON: Thanks, yeah. Just one more comment on it. The problem with the needs test, and the needs analysis, is again, it can only look out a certain distance in time, and yet the generation, the capability that needs to be installed to provide reactive has to be built in when the plant was first built. You can't add it later on. So, when you are trying to make decisions then, based on an investment, it's going to be there 25, 30, 35 years, you know, it's just too short-sighted to say, well, I don't need this generator here today. I'll forego payment for that; then, if the generator doesn't install capability, later on the grid changes and you will ultimately going to need some capacity there. And I think that was mentioned in the first panel, the fellow from CenterPoint Energy. The grid has changed in the Texas market, such that generation is being imported now, rather than being generated local. And it has changed the complexity of reactive supply.

MR. HELYER: Let me just add one thing to that. As John is saying, we're being asked to provide or build in this reactive whatever through the interconnect agreements, through the standards, through the good utility practice that is out there today, and has been out there over time. It is something that everybody is continuing to do. To sit here and say, well, we're going to continue that practice of every time a generator is added to the system that you've got to provide it excitation support and capability, but sit and say that we are not going to allow you to be compensated unless you actually run, or what have you is contradictory to the way everything has always been done. Power plants have been put into rate basis and people have been compensated for doing this throughout time. And we need to continue to keep that comparability moving.

MR. KUECK: Okay. The question I had gets back to the analogy with the policeman, where if we have a reactive power source very close to the load, perhaps, he should receive a salary. And perhaps, ones that are more distance from the load should get paid for the number of bullets that they expend. I guess the question is, there might be potential for some pretty major sources of reactive power close to the load, if they can get paid a salary for things like large synchronous motors being used as synchronous condensers. Or maybe even induction motors with variable speed drive could be used to supply reactive power. And that could be especially true, I think, if the salary reflected what we have been hearing today, that reactive power supplied locally can have a much higher value, because what it does for the system. Would that be a cause for heartburn if the reactive power being supplied locally did receive a much higher level of compensation or salary?

MR. BETHEL: It would not be a source of

heartburn to us. We've heard a number of people say that that's going to give you better control, and be more efficient; and allow the transmission system to supply reactive load. Instead the generators would only need to supply the reactive that the transmission system itself needs. And that's what was the basis of this Schedule Two service to start with. It was never intended to be reactive supply from generators for load. That's too far away. If the AEP is the standard for an operation distribution system just at the interface between distribution and transmission, we do our best to maintain unity in power factor.

So, we do want to encourage reactive sources at the local level. We try to make our retail prices encourage customers to do that; and not to put on a bunch reactive that drives up the voltage at night; which can cause you have to set the taps down, and keep voltage reasonable at night, and then you've got a problem during the day. So, we see those local sources in the generators look very different.

Generators, we think, should be playing head to head, and getting paid for what they do. After all, the changes that we've making in this industry have been to put generators in competition. And I think it's going the wrong way, if instead of bringing regulated generators out in the market. We are brining merchant generation under regulation, and paying them a salary.

MR. O'NEILL: So, what's the logical conclusion there?

MR. BETHEL: The logical conclusion for me was something like the ERCOT method. It says, generator, no matter who you are, it doesn't matter who owns it. If it provides reactive support and helps the transmission provider, whether that be an independent transmission provider or in an area where there is still a vertically integrated utility providing transmission service. If the generator provides service and gets paid, if it has to sacrifice any sales, it gets compensated. If it starts up, in that mode, where it's only being paid for performance, it should be compensated.

MR. O'NEILL: In the theme, technology neutral, and I think what John was getting at, would you include load in that process? Would you include devices that we now characterize as transmission in that process?

MR. BETHEL: I would include, as we started out, those devices that are on the transmission distribution systems in those rates.

MR. O'NEILL: But could --

MR. BETHEL: Those are single purpose things.

They don't have the opportunity to earn their revenue requirements from selling megawatts.

MR. O'NEILL: I think John's point was, and correct me if I'm wrong, that load can produce reactive power, along with generators. And it can absorb reactive power, as generators can. And so, if you're going to propose some kind of compensation, you want it to be technology neutral. So, if the load can provide either a transmission device -- or what we characterize as a transmission device can provide it, they should all be able to come to the market and offer their services.

MR. BETHEL: But not necessarily under the same pricing.

MR. KUECK: Yeah, the clarification I would want to make is that the load, just because of where it is, okay, might have a greater value per mega VAR, than the generator. And that's not market power. It's just because of where it is. And so the salary that the load receives; and it might be a different mechanism for the load; using this policeman analogy, that I'm going to use for generators. So, the salary that the load receives would be --

MR. O'NEILL: But in any bus VAR in the system, the unit of reactive power getting there, to that bus VAR should have the same value. So if the generator delivered a unit of reactive power to that bus VAR it would only be compensated at that bus VAR.

MR. KUECK: I see what you're saying. But it is much harder for him to deliver to that bus VAR.

MR. BETHEL: There's a lot of losses in this. I mean, basically you have to swallow the losses.

MR. KUECK: You're saying force reactive through the transmission system down to that local level?

MR. BETHEL: Do what is most economic. The general argument, I realize this may be heresy, was that yes, you design the system to be reliable, but after you have reliability, the next thing you want to do is run it most efficiently. And run it most efficiently means to choose the least cost alternative to get what you need. And that could be reactive power for load. It could reactive power from generators. It could reactive power from a device that John will sell you. But it's technology neutral.

MR. SIMPSON: Excuse me, one thing I think that is being left out here that Mr. Bethel is leaving out, is that ERCOT does not have a Schedule Two reactive charge. The load does not pay for reactive power. That cost is buried in the energy price. So, when he says, yeah, you get paid for start up costs, or lost opportunity costs, if you have to back down real power, that's true. But there isn't a reactive charge that the load is paying for in ERCOT.

MR. BETHEL: And I don't necessarily think that load should be paid reactive charge. The generators supplies are needed by transmission. So, it's supply issue, not a local load issue. As long is the load is supplying the reactive, it needs to give unity VAR back to where it's connected. The other reactive is a generator issue from our point of view. Did the generators getting to load cause the transmission system to reactive supply?

MR. O'NEILL: The problem I'm having is we keep citing unity power factor. I mean, I don't know how to categorize that. I mean, unity power factor me, is unity power factor. It doesn't say it is the cheapest way to operate the system. It doesn't tell me it's the most reliable way to operate the system. I mean, why are we focusing on unity back up?

MR. BETHEL: Do you have an alternative?

MR. O'NEILL: Yeah, reliability.

MR. BETHEL: The reason we focus on unity power factor is because it frees the capacity in the lines to provide megawatts to customers. It makes the whole system more capable if the lines and the transformers are not being loaded up with reactive return.

MR. O'NEILL: So, as to lower the cost of delivered power to the customers?

MR. BETHEL: To lower the cost to the customers, yes, sir.

MR. O'NEILL: And you wouldn't do it, unless it did that?

MR. BETHEL: Did what?

MR. O'NEILL: You wouldn't operate the unity power factor unless it lowered the cost of delivered power to customers?

MR. BETHEL: You wouldn't do it if there were no benefits.

MR. O'NEILL: So, the ultimate goal is to do things at the lowest cost possible, and a (coughing, inaudible) is operating unity power factor, but that may not always be the case.

MR. BETHEL: It's the lowest cost possible, consistent with reliability --

MR. O'NEILL: Of course.

MR. BETHEL: -- reactive down the transmission line to the customer is not the most reliable thing to do.

MR. O'NEILL: If you have capacity to do it, why not?

MR. BETHEL: You don't have capacity.

MR. O'NEILL: Losses are an economic issue. Kevin?

MR. KUECK: Good morning.

MR. O'NEILL: It's afternoon.

MR. KUECK: You're right. Good afternoon. It's before lunch, so it seems like it. I think there are three or four issues on the table. Let me just pick one of them and pursue it. What is achieving comparability load generators and supplying reactive power from generation to the transmission. And we've heard two ways to do that. One is, make capacity payments to everyone; and the other is a version using the ERCOT method, which Mr. Bethel supports.

The ERCOT method seems to have a lot of appeal because it doesn't charge Mr. Mosher's customers for capacity not needed. But I hear Mr. Simpson and Mr. Helyer say, if I'm interpreting it right -- well, slightly different messages. Mr. Simpson seems to be, if I heard you right, the ERCOT method, pay me for what I need, or pay me only if I'm called upon to act outside the plus or minus .95 bend, will not give a new generator an incentive to invest in reactive power capability. That's sort of your part of the question.

And for Mr. Helyer, I heard you say, we're required by reliability rules to have these capabilities anyway. So, there is a societal requirement that's not compensated.

So, the question for you two is, does the ERCOT method have those two deficiencies, or does it somehow overcome them in ways that I'm missing.

MR. SIMPSON: Scott, help me out here if I mess up here. But I do think the ERCOT method does have a standard, interconnection standard for generators for certain power factor capability, and so they have to add units that meet those standards.

MR. KELLY: And are they compensated?

MR. SIMPSON: No, there is no compensation for reactive in ERCOT. So, low doesn't pay, and generators don't get paid. The generator has to collect all of his revenue through his energy sales, nothing for reactive. But that applies to both independent generators and affiliated generators as well. So, the ERCOT method, really, I don't think is applicable to what we have in the rest of the country under the FERC pro-forma tariff with a Schedule Two charge.

MR. O'NEILL: If the ERCOT system operator sees that it needs more reactive power, what does it do?

MR. SIMPSON: It will call on generators to provide additional reactive.

MR. O'NEILL: And does it compensate them for doing that?

MR. SIMPSON: Not unless there is a real power charge, a lost opportunity cost, or a start up cost, additional fuel costs that they incur in providing that.

MR. KELLY: What I wanted to get at is, it may be the case that ERCOT started with having reactive capability installed. I was trying to get your opinion on whether over time it will lead to inactive reactive capability installed, because generators don't get enough compensation to justify the extra cost of the extra investment.

MR. SIMPSON: I think some of that is what we heard from the gentleman from CenterPoint Energy this morning, that generators are being retired in areas that are load pockets, that have certain reactive requirements, and now they are having difficulty meeting those reactive requirements within those load pockets. And in addition some of the generator equipment that is being installed or purchased doesn't have the same technical capability to provide reactive that old generators did.

MR. KELLY: And do you lay that problem at the feet of ERCOT method that Mr. Bethel was telling?

MR. SIMPSON: No. It would be nice to, but, no, I don't think I quite can do that. Some of that is a victim of technology change. The static exciters are cheaper, and so that's usually the choice by new generator owners. And then location issues drive some of the problems with reactive supply.

MR. KELLY: A second issue, this changes the topic slightly. When you say all generators should be compensated, perhaps you mean with capacity payments. That may make my question irrelevant. But what I was starting to get at is, if generators are compensated when called on, are we in agreement that they should be paid only if called on to operate outside of plus or minus .95; as opposed paid regardless of where they are operating?

MR. SIMPSON: No, I think all generators should receive a capacity payment. Because the decision to make that investment had to have been made up front. And, you know, the Commission has typically allowed a levalized payment stream like that; revenue requirement for capacity installation. So, I think that is how they should be paid.

MR. KELLY: All generators that receive capacity payment, when, if ever should they be paid for supply reactive power? For example, should it be inside or outside -- not inside the plus or minus .95 margin, or only when you're outside; or only when there is an opportunity cost for real power sales?

MR. SIMPSON: If they receive a capacity payment, then the only additional payment they should receive would be for lost opportunity costs, or additional fuels for actually providing reactive when called upon. I think most of it should be collected in the capacity payment.

MR. KELLY: Should the capacity be dependent on the range in which the reactive power can be generated?

MR. SIMPSON: Yes.

MR. KELLY: If somebody can generate within a narrow range, plus or minus .98, and somebody else can go a much wider range, should they get the same capacity payment, or would there be a sliding scale?

MR. SIMPSON: No. It should be based on the capability. Generators that could provide it over a wider range should receive a higher payment. And the AEP methodology does that through the allocation, based MVAR squared over MVA squared.

MR. MCCLELLAND: May I pick up on that, Kevin?

MR. KELLY: Sure.

MR. MCCLELLAND: If change venues and from

ERCOT to ISO New England, ISO New England if I heard David correctly, they were synchronous condensers. They pay opportunity costs, if they are called upon to generate VARs. They also pay the opportunity cost, or the cost to go on-line for high voltage control, and they pay $1000 per mega VAR, regardless of location. Did I get that right, David? Do you have experience in ISO New England? Is that sufficient compensation to an IPP, do you feel that is sufficient compensation and to encourage a little better investment in generators? Would you vary the power factors specification for the generator itself, the size of the generator? What is your reaction those situations?

MR. BERTAGNOLLI: We don't. We don't have any units in ISO New England.

MR. HELYER: We don't have any either, but I would not be opposed to having some kind of flat type of compensation, what have you on a --

MR. MCCLELLAND: These are actually four parts?

MR. HELYER: Yeah. I'm not necessarily opposed to that. You know, it is a way of getting to the issues and what have you.

MR. BERTAGNOLLI: It's a dollar per kilo VAR if I got my math right, kilo hour?

MR. O'NEILL: For what, ability?

MR. BERTAGNOLLI: Capability.

MR. SIMPSON: Capacity.

MR. O'NEILL: But you don't have a payment for generating VARs?

MR. BERTAGNOLLI: For actual production there's no payment.

MR. MCCLELLAND: But you do pay opportunity loss, opportunity costs?

MR. HELYER: I would say, I don't know that I necessarily agree with the rates, but the concept is something that we could probably work with.

(Laughter)

MR. MCCLELLAND: Just to add this, and then I'll turn it back to the panel again for additional questions. How about the earlier point, from -- I believe it was Mike Connolly from CenterPoint, which is the type of exciter. Would that do anything as far as addressing issue, specifying the type of exciter --

MR. SIMPSON: If the generator knew at the time he was ordering his equipment what he was going to be compensated for reactive supply, and could evaluate that; I don't know of any generator that would have a problem with purchasing the equipment that was needed by the grid to be able to supply the capability of the grid, as long as he was going to be compensated for that. I mean, we would certainly be willing to do that, to make the investment, as long as we knew we were going to get compensated for that investment.

MR. MCCLELLAND: But it doesn't seem like any of those incentives that ISO New England offers -- David, if you are familiar with this, you can speak up. But it doesn't seem like any of those particular incentives would address one type of exciter versus another, as far as speed of response.

MR. BERTAGNOLLI: The type of agreement that we recognize at ISO New England doesn't differentiate between rotator and --

MR. MCCLELLAND: Right. I assumed that would be your response.

MR. BERTAGNOLLI: We are looking at including in that in some fashion a payment to non-interlocking producing devices like StatComs, or designed synchronous condensers. I also wanted to speak to one of your concerns earlier about older generation in urban areas retiring and exiting the market. We have that problem in a big way. We have a number of opportunities that we could have converted that equipment to rotating with that synchronous condenser load. Some of that has slipped through our fingers. Some of it is about to.

It's all for lack of proper incentive to convert the equipment. A simple VAR capability payment of $1000 per mega VAR per year is simple not enough. The owners of the equipment are just not interested in cost recovery. So, that also then forces us to go to new technologies, StatComs, synchronous condensers, and other technologies that may not be appropriate or reliable. And certainly not cost effective. They are almost always more expensive.

MR. SIMPSON: And there's less StatComs in service.

MR. O'NEILL: So, let me understand, you are seeing the cost of keeping existing generators, simply as condensers. Then there is a much more expensive cost for a higher tech device, but because your only compensation method is costs, you -- they're not interested. And so, obviously, somewhere between the cost of running the synchronous generator and the cost of putting in this much higher cost device is a win/win for everybody.

MR. BERTAGNOLLI: That's exactly right. We have one example there where comparable cost of a device would be around $40 million for a large StatCom. The alternative would be to convert a synchronous condenser without loosing its capability. This is another item we're interested in, when reserving duel fuel, or oil burning capability, because we're predominately gas, and we have certain issues with that. So, the conversion of the synchronous condenser was less than $3 million. So, the owners of the generator is really not interested in recovering that cost. They see a $40 million solution as being a little (coughing) but the real value of it is $37 million. Maybe they will settle for 36.9.

MR. O'NEILL: We're almost to lunch, and I promised -- I missed this morning taking questions from the audience, so I would like to open it up for the audience for participation. So, if you are interested in making a comment or asking a question come on down.

MR. ROTH: Is this microphone on?

MR. O'NEILL: Yes, it is. And please tell us who you are.

MR. ROTH: My name is Frank Roth. I'm the manager of risk application at the (coughing, inaudible) Research Institute. And I wanted to make a few comments, mostly, I guess directed towards what was discussed in the first session this morning, and a little bit about what was discussed in the second session.

I'm not an electrical engineer, in fact, I'm a nuclear engineer. And I first of all wanted to comment that the report that was issued, I thought was an excellent report. But it was silent on at least one point that I think is of particular value, that you may want to consider in deliberations. And that is the special needs of nuclear plants. As you are probably aware nuclear issues are regulated by Nuclear Regulatory Commission that put special voltage requirements on the transmission grid voltage that will be power supplied to the nuclear units in the event of an accident. This is, of course, of mutual interest because in the event that there is some disturbance on the transmission grid, particular in the conditions where the grid may be heavily loaded, the nuclear plant will check off due to the technical specifications by regulations, to include the Regulatory Commission; which of course, if this happens during periods of peak demand it will only make the grid further unstable. And situations, which is not uncommon, where there are more than one nuclear unit in a nuclear plant may, in fact, result in multiple plants tripping off and creating a rather large power disturbance, which will only further destabilize the whole transmission grid. So it is a question of reliability. And in fact, the positive feedback between the transmission grid and the plant feeding back into the grid, feeding back into other plants. So, that was the first comment that I wanted to make.

And you probably have a practical example of that, the disturbance in the Pala Verde area last summer, where, in fact, a transmission caused the Pala Verde Nuclear plant, which represented 3800 megawatts to trip off the line, which created a rather large power disturbance that was felt all the way up into the state of Washington.

Also, I might add, that it resulted in the nuclear plant, which not only tripped off line, but remained off line for seven days during the hottest part of the summer, which was a very large economic loss to the plant. It represented probably somewhere in the order of seven days times 2800 megawatts days of lost power generation.

The second point I want to make is something that you may want to consider, it came up peripherally this morning, and that was the Open Market Order 888. That is between the transmission grid and nuclear power plant operators exactly what type of information can be transmitted between the grid and the plant itself. Since there is this positive feedback between plant and grid it is important that the nuclear plants, from a public health and safety point of view, have some information in terms of the relative stability of the grid, so that in times of either high power demand, or load stability that they can take pro-active measures to lower the risk.

And the third comment I wanted to make was one about standards. In the nuclear side, we very often go to what we called risk informed performance-based standards. Where, in fact, it's not only the performance. As an example, voltage should be between certain limits. We wanted to know how close we are to the edge, if you will. That is there's an interlope -- an operating interlope which we are trying to operate a plant, or a grid, or whatever. And it's not only that we're operating within the interlope. But we want to know when we set the standards, we want to know how close to the edge of instability that will propagate into, as an example, a cascading effect, that will allow us to, in fact manage that risk. And that is not necessarily -- contingency, but it might be -- end line is two or more. We very often find that the relatively small impacts of contingencies -- individually, when taken together will have a large impact on whatever we are trying to manage.

So, that was the extent of my comments. I appreciate the opportunity to pass those on. I do commend the FERC staff for the report. I think it's an important step forward. And thank you for the opportunity to comment.

MR. O'NEILL: Kris, are you going to jump the gun?

MR. ZADLO: Kris Zadlo from Calpine. I just want to clarify something about the ERCOT method. There was a task force in ERCOT that looked at compensating the generators. And something that we have to remember about ERCOT is, ERCOT is an environment that has fully rolled-in transmission costs, including the interconnection. And what stakeholders decided to do in there, is in consideration for its fully rolled-in transmission costs, the generators would be compensated for reactive power consumption or production basis. So, we just can't take the ERCOT methodology out of context. There was the whole stakeholder process around there. And there was a lot of give and take, that's how we ended up with what we did. Just take how ERCOT compensates its generators and apply it outside, I think, it's totally inappropriate. Thank you.

MR. HENRY: My name is Morgan Hendry. I'm president SSS Clutch Company. I appreciate the opportunity to speak this morning -- this afternoon regarding the report, and I commend FERC on the report. We have supplied hundreds of high-powered clutches worldwide over many years, in the name turbines, gas or steam turbines, to automatically connected or disconnected from a generator, so that when power is not being generating the generator can be left on-line connected to the grid, so that the AVR can vary the field voltage, so either VARs can produced or absorbed, thus providing dynamic reactive power for the grid. Or so that these machines can put back to generation very quickly.

This has enabled many areas to increase power flow highly loaded transmission lines, stabilize voltage on long transmission lines; or help to correct power factor in areas of high inductive load. What provisions will the FERC make to enable owners of generating plants to equip their turbine generating plant to receive compensation for the capital investment for operating their generators as synchronous condensers; and then being able to go quickly back to generating power?

We've talked about permanent converting them to synchronous condensers. But what about a peaking plant, for instance, that may install a device that's capable of going back and for the between generation and synchronous condensing.

The FERC report referenced the above -- lists the synchronous condensers as a source of dynamic reactive power. But is it the FERC's intention that generators disconnected from their turbines fall in this category? If not, we believe generators acting as synchronous condensers also need to be included, and a fair compensation scheme adopted, as has been done in countries, such as, England, Canada, and being adopted in Brazil.

MR. LEE: My name is Stephen Lee. I'm (inaudible) Electric Power and (inaudible). I want to compliment the Commission staff for putting together a nice report. A few points I wanted to make, responding to the first session, and also the second session.

In the first session a point was made that voltage is one factor to set some standards -- maybe more so that reactive reserve. I respectfully disagree. I think that reactive reserve is very important. There's been studies done after the blackout. There are certain clearly defined minimum dynamic reserve that is needed to maintain voltage stability.

Also another point I wanted to make the concept of reactive power as a commodity is worth pursuing. Even though you can think it is imaginary, it is actually very real in terms of fiscal impact. If you look at through reactive losses in the system, and reactive demand by customers, and to reactive sources that are inherently in the transmission grid itself, and in the generators, and various reactive resources; there is a supply and demand equation that needs to be satisfied.

And the reactive reserve requirement is the minimum standard that is established to ensure that (coughing) not having sufficient reactive reserve is recognized. The third point I wanted to make, if you look at the LMP formulation, it's possible LMP formulation to include reactive prices. Traditionally, we use the real power and real losses as a way to formulate the economic dispatch problem because we were in the vertically integrated utility environment, where the reactive problem can be simply socialized, or managed separately.

But in the market environment reactive power in both performances can be treated as part of the whole problem of (inaudible) economic dispatch. By including AC power equation and reactive loses into the formulation, it is, in fact, possible to divide a balancing equation between reactive supplies and reactive demands. And we can, in fact, have a margin cost, or margin price for supplying customers' reactive demand.

Epree intends to comments to this hearing.

MR. KANONIS: My name is Ray Kanonis, and I'm with Utility Resource Consulting. And I have done quite a bit of work in reconstructing, and also in pricing VARs. One thing in our conversation this morning and this afternoon also, we were basically talking about supplying VARs to the system and what price that should be. But there is also one thing that also have to consider, this has been mentioned earlier, is absorbing VARs, because there's too much voltage in the system. And quite often there are actually generators out on the system that pretty much absorb VARs most of the time. And those are also the areas that we also need to consider in pricing. It's just not only putting VARs into the system, but also taking VARs out of the system. And there is a going to be a little bit different thing. I'm not sure there is an opportunity cost there. But we have to look at what is going to happen to those generators, as they are actually absorbing the VARs.

Thank you.

MR. O'NEILL: Any last minute questions? Jose?

MR. RUCKER: My name is Jose Rucker. I just wanted to pick up on something that Phil Fedora said this morning, which I applaud the Commission to finally look at this. That is for many years now we've been trying to get the Commission to focus on transmission connections as part of the standard. And for whatever reason it was never addressed. I was very happy to see it. We strongly support the Commission looking into this matter, to have some kind of standardized rule for transmission connections. Thanks.

MR. O'NEILL: Anyone else?

MR. BETHEL: It's between you and lunch.

MR. MEAD: Okay, I'll be quick, Dave. Someone said the generators are not compensated when they provide reactive, but under their -- they are paid, $2.65 per mega VAR hour of the instructed reactive, whether it's absorbing or supplying outside of a band, plus or minus .95 percent power factor. Maybe those generators never operated outside of the range where they were getting paid.

Also, I think if you compare where the large generator interconnection policy eventually ended up, when that started, I would agree that there was a fair amount of interconnection facilities signed in as generators. But as that process moved along, the Commission steadily moved the interconnection point closer to the generator, so that more and more facilities would find the system upgrade. So, I don't think you'll find that the standards in the rest of the country is all that different from that for the generators.

UNKNOWN SPEAKER: Can I just ask one question? Where does the money come from when the generators are compensated for their reactive power?

MR. MEAD: It's a market charge.

MR. O'NEILL: With that, see you at 2:00.

(Whereupon, a luncheon recess was taken.)

MR. ALVARADO: I've learned years ago that the toughest spot is the first spot after lunch, from years of being a professor. I am the chairman of IEEE USA Energy Policy Committee. I'm also a consultant for Christianson and Associates, and for 30 years I've been a professor, and I'm still a professor. I professor at the University of Wisconsin working with a group called PCERT, which is a consortium of universities.

This afternoon, I understand we're here to come up with some solutions. And to me that means technology incentives and rules, and all the things we can bring to the table. The morning speaker, first speaker started with an analogy. I don't like the beer analogy, I like beer. I don't like the beer analogy.

I want to start with a different analogy. I want to talk about an airplane analogy. You can think of the energy market as energy, if you will, at the propulsion of the plane. You think of the reactive power as the lift on the plane. It moves you forward. You want to go forward, but you also want to up. If you don't want lift, you take a bus.

(Laughter)

MR. ALVARADO: A point about lift is also very important, and I think it very pertinent. Does lift ever have a direct value? The answer is yes. Have you ever had to leave on a hot July afternoon from Jember (ph) and they tell you they have a capacity restriction. In other words, the airline has to take some passengers off. That is a direct cost. But would you want to price the lift based on the payment that airline is going to receive because they had to bump ten people off? No. It is a rare event, and they probably would never compensate for it. But it does have an analogy to it.

The issue really is, in reactive power there is the two components; the operational component and the reserves component. And in the operational component, which is, do we want to do a better job dispatching reactive power so the active energy markets work better? Absolutely, yes. Is it valuable? Yes, we want to do it. We want to even post those reactive power prices et cetera. Yes, yes, yes.

But let's not think that if we solve that problem we solve 100 percent of the reactive power problem. There is more to it. There is the part underneath the water of the iceberg. It's the reserves and the dynamic performance requirements that are very important.

The IEEE USA was concerned with these issues, and they put some on the table. You've got to have enough queue. And there are some steady state benefits to queue.

There are various flavors of reactive power, and location does matter. It matters a lot. By the way, before oversimplify, once again, I'm sorry that Joe McClelland isn't here, because he has been saying that, and a lot of people I've heard say that. We want to solve the problem at the load. No. You solve the problem of the load, that helps a lot. But that doesn't solve whole problem. It does solve a good chunk of the problem very cheaply. But it would be simplistic to assume if you have every load that you need the power from, you have solved the problem. You haven't.

You need to have enough fuel reserves, and that is done at planning stage. If you don't have them, you can't get in real-time. There is an interaction between P and queue. And queue controls are important.

If you get too aggressive or do them wrong, you can induce dynamic instabilities. It gets too technical. But a problem can be created if you try to control the voltage too rigidly. And I know that the issue that was raised by (unintelligible) seams. Seams are an issue. I'm going to be careful, but I want to tell you, is basically, be careful what you tell the market you want to do, because you might get it. And once you get it, you might not like it.

Now, the other important thing is, people having been talking about comparability. And we do not want to foreclose technological solutions. If you specify what you in things, and where do you need them, and you might get a answer than if you specify specifically things that you might want to do directly in a certain way. Let me give you a couple of examples. In the analogy of lift, if we specified lift the traditional way; the helicopter would have never been invented, because it relies on a different technology. And yet is a useful thing for certain things.

More directly in the power market, for example, we have been talking about the value of injecting reactive power at the load, near the load. How about the value that something that reduces the feeders of the line, and reduces the losses? Losses. I hate the word losses for reactive power; the consumption of reactive power.

So, there is less. And where is the incentive for that? And we do need to be technology neutral. So, all options are considered. Another big issue that is of great concern to the IEEE, particularly, is the issue of complexity and fixed costs. We may come up with the best theoretical solution, but it is going to cost more to implement and deploy than all the benefits that can be foreseen. It may be better come up with a practical solution. After all people, don't want lift; they don't want reactive power; they want energy. They want transportation.

So, in short, to close, the most important components of the solution are basically threefold. First is, correct compensation structure. I hate formulas, because as soon as you put a formula there for compensation, people are not going to work toward the right solution, they are going to work toward the formula.

And the compensation needs to based on value provided. Whoever provided -- I also hated in the earlier days when it says from generation sources. You really need to open it up. If somebody wants to be in the business of providing reactive power but is not a generation source, why not?

The location must matter. Reserves must be compensated. The reliability value has to be factored in somehow. And the -- also we should not restrict who can deploy them. You shouldn't be restricted to a particular class.

One final point; and that is software. In some sense we are limited and that is because of software capabilities. We barely can make it work for active power. I would hate to jump into something that was too aggressive in the reactive power arena until we knew that the software was capable.

MR. O'NEILL: Thank you. I just want to make announcement before going to the next speaker. We've added one person to the panel here this morning. I'm sorry, this afternoon, making it truly and international conference. Tom Rusnov from NR Canada -- or NRCAN, I guess, right?

MR. RUSNOV: Natural Resources Canada, NRCAN.

MR. O'NEILL: He has joined us, and Andy has his name tent.

MR. RUSNOV: Can I hide under it?

MR. O'NEILL: You can do whatever, you can take it home as a souvenir. Mr. Calviou.

MR. CALVIOU: Thank you very much for the opportunity to speak this afternoon. And I'd like to extend my compliments to staff. This is an excellent report. I thought this was a comprehensive work. It laid out all the issues and the technical issue underlying it very well.

As you know, National Grid is a distribution company in the Northeast. We operate both in New England and New York. So we have experience there. And we're also involved in Grid America, an independent transmission company in the Midwest.

As Grid America we are part of the Midwest Standalone Transmission Company, and Harry from ATC will be giving comments on the end stats as well today.

As you can tell from my accent, I don't originate from the US. I've come over from the UK. And so I also have experience in the UK arrangements and what we've done reactive power over in the UK, which I can hopefully share with you today.

I think as we've heard today, reactive power is pretty fundamental to the operation of the transmission system. And it's quite a contrary product, in my opinion. Everybody goes on about how it needs to be generated locally, needs to be provided locally. It doesn't travel well. But on the other hand, if you get it wrong, it can really effect the large scale long distance transmission.

We heard a very good example this morning from the representative from NPCC, where a lack of voltage support on the border of New York and Pennsylvania affects the transmission capacity on the HVDC links between New England and Quebec. So, yes, it's a local product, but it is needed for long distance transmission. So, just thinking of it purely locally is a mistake.

We believe reactive power isn't a product that is suitable for a real-time market. Partly this is due to the local nature. Partly I think this because of the relative size of cost within dealing with reactive power compared (inaudible) power market. To give an example, in New England the reactive generators are less than $20 million per year. This compares to a $5 billion per year real power market. That's less than half a percent.

So, I think the important thing with reactive power is making sure that it doesn't distort and cause problems in the real power market, rather than trying to find incremental minuscule savings in terms of reactive power cost per se.

Certainly, in the UK, when we worry about reactive power, and we do probably a lot, because we have a lot of voltage constraints in our system. The big we're worrying about on reactive because of that voltage power constraint. Are we going to have run an extra generating unit in order to provide their electric MVARs? That shows the cost of reactive power in the real-time market, and I think we shouldn't completely forget that.

So, if we don't believe a real-time cost-minded market, which I think as well as having possibly small benefits, I think we have quite a few crossovers in terms of the cost of revenue quality metering, which would probably have to be installed on a number of generators. The cost of the software, as well as transaction costs.

What do we believe in? Well, we posed a simple pragmatic regulation model based on our experience in both the UK and the US. The elements of this, I think, first of all, we think all generators should possess a base level reactive capability. Typically that would go out by the large generator interconnection agreements. So, .95 to .95, typically in the US. I do know in the UK our base level is much wider, we worked .85 to .95. And we think all generators should be paid for this capability.

I think the reason that generators should be paid for it, and I think you can debate should they paid for it explicitly or it should it be under some sort of pass through payment or paid from the energy market. I think it's valuable that a generator be paid explicitly, because when generators maybe have some sort of maintenance issues with their machines, when the reactive capability is impaired, and if they are not be explicitly paid for that capability then they have no incentive to restore it.

Well, you can say it's a requirement, so they ought to restore it. But I certainly know in my UK experience, the reason why we took reactive power very seriously was generators were getting to the state where they were saying, no one is paying me for this capability, so why should I pay spend any money to capability going? When the regulator was willing (inaudible) was because they had sympathy for that argument.

So, I think payment for that capability is appropriate. We also think there should be cost reflected payments for any costs related to the use of the capability, such as loss of profit payments, loss opportunity payments when generators have their output reduced because of reactive power; start up payments when they're increased. And we do think the arrangements in both New England and New York work well in this regard.

It's probably worth saying, actually in the UK, we don't explicitly pay on capability. The basic payment is on utilization. And even though we do that in the UK, we're not recommending that here. A couple of reason, in the UK we did move to a utilization on the basis, well, let's only pay for those MVARs you need and use. But I think most engineers tell me, I'm not an engineer myself, but certainly a lot of my colleagues do, the most valuable MVARs is the one that (coughing). So, it's not the utilization of the mega VAR, it's having capability in the system.

I think another problem with paying generators based on capability, as we faced on utilization, is they suddenly get very interested in other things going on in the system, which may affect the amount of MVARs they are either consuming -- either generating or absorbing. So the next time a transmission owner wants to put a SPC on a condenser on the system in order to meet some of the reliability requirements, a generator may look at that and say, hang a minute. We have reliability factored on the system may reduce the amount of MVARs I'm going to generate. So, therefore we have a big incentive to do thing -- to object to the investment in the transmission system.

I think what I will next do is the reactive needs of the system need to be looked at as sort of overall system planning. I think the transmission provider does need to look at the system requirements and really get a handle on what's need. And to do forward looking for active planning, looking at all possible resources, generation, transmission, and then decide.

Clearly, we have this basic capability which is supposedly being paid for. But then beyond that basic capability, then I think the transmission provider should be able to forward (coughing, unintelligible) for the contracting market basis to find the optimal mix, lowest cost mix of reactive. So, the idea of contracting for reactive service in generators who can provide, a range of .95 to .95 would have to be under a reasonably long term contract to make that investment worthwhile.

The idea that we heard about in New England if a generator can be converted into synchronous compensator, again, the transmission provider should get paid for that on a reasonable basis. And also looking at additions to the transmission system, whether that additional reactive solution, such as condensers or SBC or all the more high tech stuff we've heard about.

So, I think the transmission providers doing this forward looking planning can then find the lowest cost solution. It can find the answer that's in the best interest of the customer. And you'll notice, I think therefore, by definition this planning has to be both economics and the reliability. Clearly, reliability is important, but we do want to find the most efficient solution. And therefore we have to look at the economic aspects of the system.

We do believe that all generators having been paid for reactive capability should be subject to system operator instructions, and provide reactive capability when need. So, they should be willing start-up when they are instructed to. And they should be willing to reduce output in order to provide MVARs when they need.

We think this model is readily commonsensible. Many of the elements needed to it are in place today, such as in LGI. If you look at New England/New York, a lot of the elements are there. We think it strikes the right balance between the need of the customer and the need of generators. And, particularly, a for generators to not be disincentivized to help the system, in terms of providing reactive power.

I think it does need more sophisticated

planning to be developed. For example, I think of a number of RTOs and ISOs, their planning is probably is comprehensive in terms of voltage levels. The New York ISO only tends to the bulk power system it (unintelligible) kV and above. We've heard today about how the low voltage levels are important. That tends to get delegated to the individual utility, and I think a more comprehensive process is required in order to take up a comprehensive, system-wide view reactive requirements. And I think also that planning needs to be more scenario-based. When we are looking at real power, we do take into account uncertainty. I think just planning for peak and contingency is not necessarily good enough. I think we can be sophisticated in understanding what the requirements of the system are.

And the final part of the puzzle, I think if we are paying generators to provide this capability, we do need a good system of testing, in order to prove the capability that we actually paying them for.

Thank you very much.

MR. O'NEILL: Mr. Sasson.

MR. SASSON: There seems to be a consensus around certain themes today. And although I have written my comments, I'll emphasize those areas where I think there is some consensus. Maybe not with the unanimity, but there appears to be some consensus.

Provided we accept going in that this world of ours is divided into two parts. One, those areas that are organized under ISOs and RTOs, and those that are not. The situation may be different. We may not be able to have one of set rules or on set of guidelines.

My remarks are going to be more on the steady state, rather than the various -- I'm just not going to be talking about that. I'm going to make some assumptions for my discussion. One, I am part of an ISO/RTO that is responsible for scheduling and administering a tariff. I'm also going to make the assumption that system planning studies are being performed, both the transmission owner utility, and by the ISO, in our case, New York with a horizon of maybe five to ten year.

So, we're dealing with a situation after all that has happened. Basically, what it means is that the system does have enough reactive resources. If not, those studies would have shown there had been some deficiencies on the line down the line and something would have been done about it.

The question is: we have the resources that we have, how do we administer it? How do we schedule? I am going to talk then, with that background, about three things. One, to acknowledge reactive power contribution to reliability. I thought that was an important subject, but I guess there is consensus around that one. I guess no one in this room considered anything to the contrary.

Second, that we must compensate financial for reactive power production capability. And I think that is also one that I think there is quite a bit of consensus in this room. And third, probably a subject we haven't totally talked about, although it has been touched upon by a couple of speakers. It's improving how we schedule reactive power, how ISOs/RTOs schedule reactive power.

So, let me start with the first one. Acknowledging the contribution of reactive power for reliability. If we're going to accept, then the next step would say, well, we should make the provision of reactive power mandatory for all suppliers that are connected to the system. Reactive capability must be verifiable. Verified by testing. That's another one that I think many, many people are discussing that. So, there seems to be consensus on that. Why is it necessary to test? Well, for a lot of people you to test because it's associated with compensation, and rightfully so.

We also have to test so that Mike Calvious of this world know what to expect minute by minute. What reactive resources are operating in the system. Do they really the tools that -- what tools do they have to operate.

There seems to be unanimity also on another point, which is: suppliers must follow the instruction of system operators. I heard a number of speakers say that. We must do so in a way that we have that would not harm it financially suppliers of reactive power. And I think we always need to have rules that encourage people to do the right thing. If you want somebody to do something, but he is going to be harmed if he does it, that doesn't look like a very logical incentive.

It's also important, I think, I've heard speakers, that there are different types of equipment out there. For example: there are generators that can have a wide range from minimum to maximum. There are base load units. Both have a function. Both are needed. But from a reactive power point of view, they are different. They provide different services. They have different, perhaps, value to the system. The base load units are very close to one per unit power factor, but not exactly at one. And while units that have much wider range can achieve a .3 power factor. So their contribution is very different.

Okay. That's the first issue about the reliability and being mandatory tested; and recognizing different kinds of unit. Now the compensation would then need to follow the fact that, yes, there are different kinds of units. The amount of money involved in reactive power is, as many speakers have said, it's very small compared to real power. So, we should not have such a complex system that it is so expensive build that a ISO/RTO to operate and monitor. There is not only software, but you need a lot of people to monitor it, we're going to say, well, I'm going to pay -- if a particular unit goes from .9 to .89 power factor. You need to have the infrastructure that can follow that, and make sure that that is happening. And some of that needs to trickle to the billing. All of that costs a lot of money and effort and people on the ISO/RTO side. So we need to make sure that we keep simple and consistent with the amount of money that's really involved here. That's why we feel like the other people in this room that a cost based approach doesn't mean, not necessarily the AEP method, but a method that is somewhat related to cost and including a fair return on investment. And enough money involved, as many speakers have said also, units can be well maintained, that the reactive capability for units are maintained.

So, based on that, we would suggest that units be tested and paid 100 percent level or real power for the amount of MVARs that they can produce at that level. That is possibly what I would call the highest service that a unit can provide. When load is high and units are at peak, and voltages are low, we would need to have the units produce as much reactive power as they can. And so, therefore, the amount that they can produce at peak is a very high value.

However, as a few of the people here have noted, a unit that can go down, let's say 55 or 40 percent of peak and still produce much more VARs, we think that it's all right to pay those units additional money, perhaps at a lower rate, for the additional VARs that they can produce at a lower level. On the -- I was talking on the lagging side.

On the needing side, we think that 100 percent real power, there needs to be a significant payment at the highest rate. But also recognizing that at 2:00 in the morning we need units to absorb VARs. that those units that can really come down and absorb VARs at, let's say, 40 percent of their peak value of real power, they also need to be compensated. We need to recognize those. We need that service also.

So, I think that it's possible to come up with a criteria that is consistent with needs of the system of the services provided. The actual rate can be different in different areas of the country, because the ISO markets are different from each other. There are some similarities, but there are some differences. We need to make sure that we don't pay twice for this service. But barring that, I think it's very important. I think a number of speakers have said, to encourage generators to do the right thing, and maintain their units.

My final comment is in an area that less number of speakers have talked about. I think you mentioned this morning, you want to run the system most efficiently as possible. And a number of the speakers have said, how do we know what the system requirements are?

Well, I think one person had stood up and talked this morning mentioned something -- today all ISOs/RTOs schedule real power. And their software system, perhaps, optimize, I think in the case of New York ISO, energy reserves and regulation. We have reserve constraints. But all real power, maximum and minimum units, all the constraints are based on real power. And based on that we produce an optimum schedule. Now, because we are dealing with real power, that was the charge of setting up the New York ISO systems for the transmission owners in New York in the late '90s. One of our greatest concerns, we're going run the day-ahead market, closer to 5:00 a.m. in the morning. By 11:00 we have to announce prices. We have an enormous amount of computation to do. We have to do this with an internally -- with a software system internally, just based on DC load flow, which is a real simplification. And they look at the computer much less time.

I think today we've gotten over that. I think we have now, as part of our computer systems, and we have enough experience of running ISO/RTO systems that we may not need to keep that. We do, as one of the speakers said this morning, if we internally replace DC load flow with an AC load flow, we can now then model reactive constraints.

And here I just want to make a point to be sure that it's clear, I'm not advocating people bidding in reactive for the same way as they do for active power. And I think the report, staff report I think very clearly, says this is probably ten/twelve years in the future. And I think that was generous. I'm not advocating that. What I'm advocating is from a point of view of what market buyers and sellers do today, there should be no change. They still buy and sell real power. But internally to the software system schedule the system, you can have voltage constraints so you say, okay, I'm going to schedule enough units, such that I'm able to meet -- to keep the voltage within a certain reliability band at all locations, not only under normal conditions, but also under contingency conditions. And if we do that, I think to some extent we answer the question, well, what are the system requirements? Well, the system requirements are the ones that the scheduling software produces. And in answering Dick's question this morning, it will do it at optimally, in the most efficient manner.

So, we think that there needs to be a requirement going forward that ISO/RTOs seriously look at modeling reactive and voltage constraints inside their system. So, I think I'll stop there because we have time for more questions later. But thank you.

MR. O'NEILL: Thank you. For those who were expected Steve Naumann, he wasn't able to make it today. And we have substitute from Exelon, we have Ms. Susan Ivey. Go ahead.

MS. IVEY: Good afternoon. I am the short term pinch hitter for Steve, so I'll try to do my best to replace him, but keep my comments short.

As far as a long term solution for reactive compensation, we see three basic principles. One -- and many of them have already been aired by many of the commenters here.

First is that reactive resources need to be installed, available, and provided to maintain the system reliability. That is a basic tenet. Two, providers of the reactive power and voltage control need to receive reasonable compensation for the services they provide. And three, the customers who pay for it need loss of pay of reasonable price for the service.

Our proposal to modify the existing system going forward sees that generators should be compensated on a cost based system. Where interconnections agreements are under tariff filings already exist, those terms should be kept, and the generator should be able to continue to receive the compensation based on the performance that's in the interconnection agreement, that's laid out in that. If it says a .9 power factor, then that's what they should be meeting.

But a generator with an existing revenue requirement, assuming there is any kind of misalignment between the interconnection agreement and the filing that has been made for their requirements, they should have opportunity to either pro-rate or make a new filing for new revenue requirements as a result.

If a generator is called upon to perform outside the range of the interconnection agreement, payment should be adjusted to reflect that performance. Performance should also be affected. The payments should be affected by the unit's performance as well. So, in the case of RTOs, we believe that they -- an RTO should divide its performance criteria through a stakeholder process. And it should take into account their criteria. Much like the ITAP process in PJM, as it exists today.

Factors that should be considered is that reactive power is provided when it's needed by the system, and system operator has the support. It should based on the generators availability to provide that resource. It should also be based on the availability of voltage regulators. All generators should have a their voltage regulators available at all times to perform with the system.

And there should be reactive testing to ensure that they are meeting the requirements that have been laid out for them. We also believe that payments for incremental capability beyond that which is covered by the interconnection agreement, or existing tariff filings, should be competitive with alternative solutions. I'm sorry. Payments for incremental capability, meaning those unites that do not have an interconnection agreement, or have not yet made a filing for compensation, that should be done, or that should paid for on a competitive basis. So, it should be run competitive to other alternative solutions for meeting the requirements of the system, such at the static VAR compensator.

So, in the case where a generator wants to file for compensation, but there is a potential alternative available that might cheaper, that alternative should be considered and paid for prior to the generator being paid. And that aspect should be part of the process. So, the planning process should be looking at, what are the needs of the system? And then if the generator wants to be compensated, they should have the option to either provide that reactive resource based on a competitive alternative, so if SBC is cheaper they should be given the opportunity to provide that revenue for reactive capability at the same price.

So, just to reiterate, the three main principles: our ultimate goal is to acquire the right amount of dynamic reactive power at diverse locations, so the system can be operated reliably and within voltage criteria, but with a fair and balanced treatment to both generators who supply the power, and to consumers who pay for that. And with that, that completes my comments.

MR. O'NEILL: Thank you. Mr. Clarke.

MR. CLARKE: Yes. I'd like to thank the Commission for this opportunity to address the future treatment of reactive power issues, and Commission staff for an excellent, exhaustive analysis of reactive power issues in its recently released White paper. I'm here in my capacity as a consultant to LIPA, which is the municipal utility serving Long Island, New York.

I'm here today to provide observations regarding utility and merchant transmission facilities who contribute reactive power capabilities. As you may know, LIPA has advocated the development of merchant transmission in the Northeast, including the Crosstown Cable which interconnects from New England LIPA's transmission system. LIPA currently holds the long term rights to transmission service over the facility and rights to Crosstown Cable's other capabilities, which include ability to provide to reactive power.

A second merchant project to Neptune Cable connecting LIPA to PJM is also planned. The Crosstown

Cable is an HVDC light facility with about 300 megawatts based on IGBT technology. The Crosstown Cable's terminal equipment is able to provide net leading and lagging VARs in dynamic time frame, only in higher range of capable power flow.

If its terminal equipment is energized, even at a zero flow, it will respond and dynamically adjust reactive power production or consumption, usually to preset voltage schedule. Like other IGBT technologies, it has excellent performance in transient low voltage conditions following a fault. That (coughing) market ability, and the facility is recognized as being comparable to or superior equivalent generation.

In fact, ISO New England has routinely relied upon Crosstown Cable as a source of reactive power. For example, between September 2003 and may 2004 the Crosstown Cable was called upon, approximately, 135 times. It is through affirmative require of ISO New England, or New York ISO for a through automatic response to provide voltage reactive power support to protect the stability of operations on the electric grids on either side of Long Island Sound.

The issue is payment for VAR support. At this time neither the New York, nor the New England ISO tariffs compensate nine generator like Crosstown Cable for reactive power that such facilities provides, nor are these costs folded into LIPA regulated ranges for transmission. Thus, even though the terminal equipment is a valuable source of steady state and dynamic reactive power, no compensation is provided. Moreover, those parties that pay for the transmission service over the merchant transmission facility are not the parties that reliability of the facilities VAR being capability. Thus, a small number of transmission customers subsidize reactive capability from a wider set of customers benefit.

Such subsidies provide a disincentive for merchant transmission developers to include net reactive power capability into future projects. An issue that councils on compensation could address. I would note that NEPAL and ISO New England have initiated a review of the treatment of reactive power in New England. That review will include, among other matters, potential compensation for non-generator reactive power sources, like the Crosstown Cable. LIPA is participating in those discussions and looks forward to a productive discussion on the future treatment of reactive power in the NERC market.

We agree with the White paper's conclusion that long term changes in policy are likely to take some time to implement. The conclusion that comparability issues can and should be addressed well before a comprehensive reworking of reactive power markets is also well founded. We believe the Commission should specifically address comparability issues for merchant transmission. Moreover, reliability benefits for merchant transmission VAR capability. For such capability can be established should be compensated for similar services provider by generation. Thank you.

MR. O'NEILL: Thank you. Mr. Terhune.

MR. TERHUNE: Thank you very much. I appreciate the opportunity to speak at the conference. And I thank you very much for the invitation.

I'm Harry Terhune, I'm vice-president of operations at American Transmission Company. I'm speaking for the Midwest Standalone Transmission Companies, or the MSATs. Now this is a group consisting of American Transmission Company, GridAmerica, International Transmission Company, and Michigan Electric Transmission Company. The MSATs are FERC transmission companies whose sole purpose is to invest in, own, plan, construct, operate, maintain and/or manage transmission facilities. We do not own generation, buy or sell energy, or serve retail customers within the Midwest Independent Transmission

System Operator region.

The MSATs typically do not receive or pay for generator-supplied reactive power compensation, but we recognize that generator-supplied reactive power is a large part of the overall mix of reactive resources that is critically needed for reliable and efficient operation of the transmission grid.

Basically, for the MSATS everybody looks like a customer. I'll skip the basics because we've done that three or four times already today. So, I'll indicate that among the MSAT community some of the reactive resources that we deploy or operate include the typical static capacitors, generators with their VAR capabilities. We have peakers with synchronous condenser capability. We have superconducting magnetic energy storage devices with dynamic VAR capability. And we even rent distribution caps from distribution companies to provide transmission assistance to defer future transmission investment to the extent possible.

We believe that financial compensation for generator supplied reactive power should be comparable and equitable for those generators that supply comparable voltage support services, regardless of ownership within a particular region. This methodology should accommodate existing reactive support arrangement.

We think the Commission should consider the following seven principles regarding reactive power. First, insufficient reactive power capability has been a major or critical factor in many regional blackouts. Because of the importance of reactive support for reliability and operability of the transmission system, the local nature of reactive support and the need for an appropriate mix of different types reactive resources that are not readily interchangeable, reactive power is not conducive to trading in a competitive regional market, and is inherently prone to local market power concerns. Equally, reactive power should not be permitted to be withheld by a reactive resource owner seeking a higher price. Reactive power, therefore, may best be treated as a regulatory requirement recognizing that different requirements may exist for different types of reactive resources under different regulatory regimes.

Second item, from a standpoint, the costs associated with moving toward a real-time reactive power market are likely to outweigh the consumer benefits. We heard some discussion before of the relative costs of the reactive power -- total revenue requirement compared to real power. So, I'll skip over some of that material that I have here. But the costs are small compared to real power. It's more important to make sure that insufficient capability does not result in either reliability problems or inefficiencies in the real power market.

The third issue, centralized control of, and planning for reactive supply from both dynamic and static devices as a function that should be performed in accordance with the relevant reliability standards and criteria that FERC, NERC, regional and local systems establish.

As an aside, whether you're a little distribution co-op, or muni, or a small integrated utility, or modest sized transmission company like the MSATs, or a very large integrated utility, like say, Southern Company, or Exelon, you can't run and you can't hide. You have a service obligation that you have to fulfill. So, that the obligation to ensure that reactive capability is there resides with the party that has the service obligation, regardless of what the sources are. And that forces that utility to do the planning, to make sure that the adequacy of reactive capability, along with the adequacy and security of megawatt delivery is there.

Although there are multiple forms of reactive support, different reactive resources provide different benefits, depending on system conditions, and the location and nature of the sources. Any policies for generation based reactive resources should not interfere with the planning of non-generation resources required for reactive support of the transmission or the distribution system infrastructure.

Fourth issue, since reactive power requirements are dependent on constant changing system conditions, such as load cycles, generation, active power dispatch, and system plan, and unplanned outages, voltage enhanced reactive management is better determined on a regional basis through a coordinated planning process. Such coordinated regional planning should recognize the planning responsibilities appropriately delegated to stand-alone transmission companies.

The fifth item, generators should be eligible for compensation for the reactive support required to maintain system voltages under a range of system conditions, both inside and out side the power factor range required in their interconnection agreements. There's an innate requirement for generators to supply and absorb reactive power to ensure their own steady state stability and transient stability. And to provide adequate voltage for their auxiliary to stay on-line. The power factor range under discussion should represent that essential requirement. MSATs do support comparable compensation within the range.

Such compensation for dynamic reactive support should, in general, be to ensure the availability of reactive capability, rather than a mega VAR commodity quantity usage payment, to ensure that planned reactive capability is available when and where required.

Generators must provide reactive capability when called upon, and in doing so should be appropriately compensated for additional costs, such as start up, or lost opportunity costs. The transmission system requires active power -- reactive power to maintain voltage and stability under both normal and emergency conditions, and to offset reactive power losses within the transmission system.

Planner seek solutions that help to reduce the delivered cost of energy by including an appropriate selection of reactive power resource, including capacitors, and reactors, as well as dynamic devices, such as static VAR compensators and other non-rotating devices. But principally, reactive capability of generators.

Reactive capability of generation resources outside the range is the primary source of reactive capability to deal with rapidly changing conditions, such as what would occur during emergencies. The loss of generation, the loss of multiple transmission lines, for example.

It's appropriate to provide compensation for this capability as needed in a comparable manner amongst the generators, regardless of ownership.

Sixth item, all generators must be subject to enhanced operating authority of the system operator. The system operator should have the authority to instruct a generator to provide reactive support by bringing it on, even if it is otherwise operating. Generators should subject to periodic testing, to ensure they maintain the required reactive capability. System operators should incorporate into their operating protocols the use of reactive power to relive congestion. Generators operating outside the direction of the system operator, in other words, generators refusing to come on, or refusing to adopt to the operators instructions should be subject to loss of reactive power payments, or such other penalties that may be prescribed in approved tariffs or market rules.

The last item, transmission devices for reactive support generally provided the transmission system owner should be compensated through the transmission provider's rates. For traditionally FERC regulated transmission providers such rates would be calculated using traditional cost of service, or at the transmission owner's option if there is a Commission approved performance based rate, that would be the approach.

I'd like to thank the Commission for the opportunity to be here, and to be able to speak for the MSATs, and I will glad to answer any questions as the opportunity arises.

MR. O'NEILL: Thank you. Mr. D'Aquila.

MR. D'AQUILA: Thank you for having me. My name is Rob D'Aquila. I work with GE. And as one of the last speaker here, I had my four key technical points laid out, which I think have been repeated about 17 times. So, I will keep it very brief, maybe look at it a little different angle.

The first point I have is that all reactive resources are not equal. There are very performance and cost trade-offs. The cost trade-offs can be about 10 to 1 from your premium VARs to commodity VARs. And each system requires a unique blend, not of one, not of the either that have blended them. And that blend changes from system to system.

The second point is one that has been repeated a lot today, is that VARs don't travel. VARs are most efficient supplied locally. We've talked a lot about load compensation here. But I think one of the key points is you cannot overcompensate the load. Overcompensating the load is just as bad as trying to supply all the VARs from generators. And the transmission system needs VARs too. So, when we talk about local, local does not necessarily mean supplying all your VARs at the load, but on the transmission system.

And in addition, the generator has reactive requirements to get it power up through its step-up transformer onto the grid. Typically, it's most efficient to supply and reliable to supply the VARs locally. So, what is right for reliability is typically the most efficient also.

The third point is electrical networks need sufficient reactive resources for normal conditions. We have daily load cycles, seasonal load cycles and dispatch patterns that all affect how much reactive supply we need on the system to maintain voltage. And those are very predictable.

The normal reactive need should be met primarily through compensation from our, if we want to call them, commodity VARs. Generators, in additional, will supply the fast changing and load regulating capability, but not the bulk of those reactive resources for normal conditions.

In addition to our normal reactive power that we need to maintain voltage, we need dynamic reserves. And a lot of people have talked dynamic reserves today. These are our premium VARs. They are a lot less predictable than our daily load cycle VARs that we need. They typically arise after an emergency loss of major piece of transmission equipment, or generation. And they have to be able to respond very quick and we need sufficient dynamic reserves for them.

This reinforces the need for not using all of our premium VARs for normally steady state control, and supplying those with commodity VARs. The rules that FERC develops in establishing these criteria, the first thing, I think the performance standard issue has come up quite a bit here. The term technology neutral had come up a lot. And I think a performance standard needs to be established, so people can determine what is the correct required dynamic VARs that the system needs, versus the steady state or the normal VAR source that we need.

And appropriate incentives need to be

established to allow people to supply the commodity VARs and the dynamic VARs appropriately. One of the things that has to be recognized is that we talk a lot about dynamic VARs. Often providing steady state capacitors, or commodity VARs frees up a lot of dynamic VARs. So it's not always an issue of adding more dynamic reserves, but adding static reserves to free up dynamic reserves.

I think those are the key points that should be taken into consideration when rules are established. Thank you.

MR. O'NEILL: Mr. Zadlo.

MR. ZADLO: My name is Kris Zadlo. I'm director of transmission for Calpine and I'd like to thank FERC for allowing us to speak at this conference. I'd also like to compliment you guys on a very well written and researched paper there.

Do we need VARs? Is it valuable? I think the universal question is -- the answer is yes. I mean we can't say it enough, the current compensation scheme does not pay IPPs for reactive supply and voltage control services. I mean that's the fact today. Not only ceding compensation, we also have to pay for that service. So it's a double hit. In many cases the utility affiliated generators do not meet their own interconnection standards of affiliate transmission providers, yet they still receive full compensation.

In one such example only 40% -- 48% of the affiliated generators complied their own reactive power standard while IPPs had to provide 89% more reactive capability. That's the current situation today. The problems with the current process are; the current takes a long and drawn out process. Today, IPPs must file separate tariffs supporting testimony and rate support and work papers separately for each generator to get compensated.

Calpine has over a hundred facilities in 22 states so, in other words we would have to file a hundred separate reactive tariffs. For us it's like Groundhog Day, we're in here every month with a new tariff. In practice what happens is the utility protests every single aspect of our tariffs, including whether or not we should get compensated at all. FERC should consider streamlining the process by clearly articulating a policy that non-affiliated generators should be compensated for reactive power in a manner that is comparable with their own utility affiliated generation. We also believe that compensation should be based on capability and not production. A great example was in the first session.

I believe that someone mentioned that there is a SMED device used in New England to increase transfer capability. Well, if you went purely to a production based methodology for compensation, that SMED device wouldn't receive any compensation because it's there that you need power factor.

Another thing to remember is how the transmission provider operates his system. He uses his dynamic reserves last and he wants those dynamic reserves at unity power factor because when that contingency happens he wants it to swing the maximum amount, either maximum lagging or maximum leading. In some the production payments would fail to fully compensate reactive power providers for the true cost of the resources.

I'd also like to conclude by articulating that Calpine would recommend that mandatory performance testing be performed by independent third parties. One of the things that the August 14th Blackout Report found that a common factor among a lot of the major outages is an underestimation of dynamic reactive output. Calpine would recommend that FERC require mandatory third party testing to ensure that the transmission system has sufficient reactive capacity. For example, in areas with RTOs, the RTO can perform a periodic test and verify the capability of generation; verify the capability of reactive reserves from those generation units.

In non-RTO markets an independent third part should be hired to perform this function to ensure non-discriminatory treatment. And that concludes my initial remarks.

MR. O'NEILL: Thank you. Mr. Ott.

MR. OTT: Good afternoon. Andy Ott from -- vice-president of markets at PJM. I appreciate the opportunity to talk in front of you today about reactive power. I promise not to talk about anything but reactive power today.

When you are talking about trying to get a solution to the problem, obviously, it's nice to state the problem, and try to figure out what are we trying to resolve here? Or, what are we trying to create a solution to? I think about the problems I see are the problems that PJM has identified. I think they are along the lines of what we see in the FERC paper. And I think there also a few other things that I would probably add in, and will.

The first, obviously, is the compensation for reactive power and voltage control capability. It really is not uniform, it's not consistent across all devices. It's even consistent between generators. So, I think the real key here, when you hear stories about David from New England -- they couldn't find a way, if you will, under the current methodology they had to incent a synchronous condenser to stay on, even though said they should. PJM has similar stories, maybe not quite as dramatic. But we have seen the same type of thing, where a device would retire when it couldn't maintain its useful life if you had a way to pay it. It simply you can't put a synchronous condenser right now in Schedule Two.

Really commonsense says, we've got to fix it. So, the answer is, we will need to fix it. The other issue is limited -- is really limited, if you will, financial incentive for reactive devices, whether it be generators, or whatever, to actually deliver their stated capability in real-time.

Obviously, there is a lot of incentive, it's called good utility practice. That's a very strong incentive. A lot of people want to do the right thing for reliability, and they do do the right thing for reliability. But if you think about lesson that LMP has taught us, a well placed price incentive, okay, creates a lot of innovation. So, the point is, if we want people to deliver we need to show that it's worth something in the market, if you will.

Then we have the issue of load power factor that we have danced around a little bit today. And a concept that there also needs to be an incentive driving the load side, if you will, to make sure whether they can produce reactive or just maintain a high quality power factor.

The other issue is, we have limited transparent information about what is the reactive state of the system. In other words, what do we need on a long term basis? What do we need over the next week? What do we need over the next month? Do I have a problem coming up? That really isn't transparently available to customers. Sometimes the RTO knows it. Sometimes it's very difficult to put that information out. So certainly, we could do better in just producing such information; whether it be in the form of price, or just in the form of instructions.

Lastly, I think when I sit down in the control room under heavy load days, one of the things you notice is the dispatchers, the people running the power system don't have confidence in what the reactive response they are going to get out of the equipment. Well, here is the stated rating that we have, and here is what we think we're going to get. That kind of phenomena I think harkens back to the issue of what's the incentive, if you will, to provide the stated capability? If there were an incentive there, then I think we would get much more confidence in what is created.

So, I go back to, those are the problems, if you will. PJM really believes we need to address these issues. This year we had actually started a reactive services working group or restarted it from the past. The group has met a couple of times. We actually believe that we need to get some of these compensation issues straightened out in the near term. And start talking about short term solutions.

So, I look at the short term solution to the problem. We have very definitely the White paper, FERC White paper had outlined compensation methods. It talked about capacity payment, real-time payment, some sort of combination of the two, or no payment at all. I think we can take no payment at all right off the top, since that's probably not the right answer. I don't believe that anyone believes provides your liability service they should get back, if you will, a fair rate of return.

I think a capacity payment is absolutely crucial. We've heard from others. I know Fernando had said before that some issues with reactive services are driven by contingency constraints. The need to have them are driven by very infrequent events. So, a capacity style payment is probably the only way you're ever going to get it. Otherwise, it's going to be like selling fresh water in a hurricane. You happen to have the reactive capability there, you're going to charge $2 million for it at the time when everybody needs it.

It's just not a sustainable model to recover your investment. So, you really need the capacity payment over the long term for those types of devices. Now we get to the real-time payments, do you need a real-time payment? Absolutely. We've talked about the -- or I just talked about the real-time incentive that needs to be put there. So, the hybrid, I think, is really the way to go, where you have some capacity payment based on, again, it could be based on cost. It could be rolled into the capacity markets and be part of that. What we call the overall cost of reliability. That's one way. The advantage of that would be a least cost solution to provide all long term reliability services. You could also have some kind of auction mechanism, where you state reactive capabilities that you need and have that offered. Either way you have some of long term dependable payment. Then the real-time payment may look something like again, another short term solution, you get no additional payment for a certain band width. Our band width at PJM is performance, reactive performance is 90 percent lag, and 95 percent lead. If you do better than that in real-time, you get a premium. If you do worse than that, you make a payment. But the point is, you have a reason to perform at that point. And again, that is a short term solution.

As we look towards the longer term, we could get into, again, we've talked through AC power pricing, we actually get AC optimization running in the control room. We could have that, I guess. There are some issues, substantive issues we'd have to deal with. It would take a long time to deal with them, in my opinion. Good -- kind of high quality data is one, to those types of, what I'll call substantial changes to the way we operate the system.

The other issue is, fundamentally reactive power losses are huge. And if you actually try to build a commercial product around that, dealing with a loss issue, from a commercial basis, I can' write you an equation to do it. But that's not going to solve the problem commercially, because you've got too many losses. So, the issue of, how are you going to hedge it? How are you going to create some form of transmission right, if you will?

So, the concept of cost, if you will, of creating such a market, I agree the cost of creating a market in real-time power pricing is probably prohibitive. The cost of fixing the compensation problem, I think is really the cost -- what's the cost if you don't do it? I think really if you look at some of the issues or benefits, if I give the dispatchers in the control room more confidence in what they're going to get from reactive services, they're going to get more real power through put. The dollar value of that is fairly substantial. I realize the cost of reactive isn't much, but its benefit to the system is huge.

So, now we get to start talking about the opportunity costs, if you will, of not doing it. So, I think in the end, if you will, in the long term we have to find a way. Maybe it's a competitive transmission compensation model, where somebody puts in a device that we've heard about in New England, where they put a device that increases the real power transfer capability by 100 megawatts. There's got to be a way to pay them the true value of that transfer capability. And that could lead to some sort of competitive transmission investment type of solution.

And you may end there before you would end up in the real power pricing. Your active power pricing is more of an incentive based solution. Thank you.

MR. O'NEILL: Thank you, Andy. I'll take the prerogative of the Chair and call upon -- and we've heard this already this morning. The NPCC presentation had a post-contingency voltage that would allow another 800 megawatts to be transferred from hydro to that.

Tom, did you want to do a presentation.

MR. RUSNOV: Mr. O'Neill, I didn't come prepared to do a presentation.

MR. O'NEILL: I thought you were joining us, so to speak, on this side of the table, not with that side.

(Laughter)

MR. RUSNOV: That would be good for me. I thank Jolene for getting me up here.

MR. O'NEILL: Okay. Back to the examining. This morning we heard that post-contingency voltage could have solved -- could have brought 800 more unites of capacity in the loop. And that wasn't unique. There's other locations around the system. Maybe there's an old clunker generator sitting there that could be run as a synchronous condenser. Maybe the distribution company, the transmission company has a rate freeze and doesn't want to build -- doesn't want to put anymore capacity in. Somebody comes to the ISO and says, just give me the FTRs and I'll install the device, and I'll create the capability to import another 800 megawatts. That's not a cost-based system.

Would you allow that to happen? And by the way, the example here has the reliability problem solved. There's no reliability issues.

MR. OTT: Can I volunteer to go first. I think if you're talking about, can someone increase -- incrementally increase the capability of the transfer capability of the system and receive a transmission right for that, the answer is yes. Under the current rules, that can happen.

MR. O'NEILL: And this is a generator?

MR. OTT: If the limit is a reactive power limit, and that generator increases the reactive power limit, if you will, that would be an incremental increase based on our definitions.

MR. O'NEILL: Yes.

MR. OTT: So, yes. Obviously, if there were a thermal limit cutting it off, then the answer would no, because it didn't address the thermal problem. But certainly under the existing rules. If the limit on the FTR is on that interface were reactive based, and they increased that, the answer is yes.

MR. SINGH: But do you need to make FTR rated in NVAs, or it's just the underlying limit is reactive. I just don't see it.

MR. OTT: Well, yeah, the real power transfer limits that we have are -- if you are familiar with the concept of transmission line loadability or the PV curve. So, we would actually translate the incremental increase into a megawatt amount, and then give them their real-power incremental increase.

MR. OTT: Does anybody else want to address that?

MR. CALVIOU: I think his example, Dick, this particular example, raises some interesting issues. One, as you know, the requirement for reactive in New York. The transmission limitation addressing (inaudible) on the line between New England and Quebec, which already has right-holders who may believe that they already own the transmission rights, and the fact that they are being restricted. So, I think there is an issue of exactly who would get the benefits.

MR. O'NEILL: They own rights that don't exist.

MR. CALVIOU: They own rights. Up to before 2000 they were not on capacity. And then actually capacity available during the day is restricted because of the capability. So, they own what you call --

MR. O'NEILL: They have rights that can't be used.

MR. CALVIOU: It's a non-firm right, I think, shall say.

(Laughter)

MR. O'NEILL: It's still rights that can't be used.

MR. CALVIOU: But I think the point that it comes out to is, I think, this shows why you need regional planning. This would require New York and New England getting together and looking at the problem, finding the overall optimum. It does need a solution. The solution is a transmission solution. Maybe there is a way of doing it merchant. A good way of doing it is straightforward transmission solution, getting the local transmission company to do it. If it is under a regional planning process where the costs can be recovered -- where the costs of any upgrades on that regional planning can be done on the ISO tariff, such as we have in New England. That could work well.

MR. O'NEILL: The benefits here are very clearly proved of the entity who is importing the power, right? Not necessarily to the local utility who may be having the transmission. So, if you take the normal solution, you may get one group paying and another group benefiting? Does that sound right?

MR. CALVIOU: No, it doesn't. I think that particular example, I think could be the nature of the HQ line. I think there are some interesting issues. But I think for your generic question about are there things that can be done, transmission upgrades, you know, maybe generator based solutions could be found to increase capability of the transmission system. I think a lot can be dealt with by regional planning.

MR. O'NEILL: That story, by the way, is not unique. I'm not sure how many of them are out there. But they are counted on more than both of my hands. Because John tells a similar story in New England. And there seems to be -- the incentive doesn't seem to be there by the entity that normally would go to the facilities. And if somebody else comes in and makes the offer, what -- how do they get the compensation? Because there is no obvious way to compensate them.

As a matter of fact, Mr. Clarke's example is another one. They are sitting there with the reactive power and I guess they are kind of like providing as a good utility practice or citizenship, or whatever. But --

MR. CLARKE: One thing I would add, to my recollection the New York Power Authority did install a FACTS device in New York. And somebody correct me if I'm wrong here, and received TCCs, which are New York's FTR equivalents for that installation. So, this has been done in New York. Is that correct?

MR. SASSON: That's absolutely correct. Could I follow up on that? You're question had a premise in there's no reliability issue.

MR. O'NEILL: I was only reading from the text here.

MR. SASSON: I wondering if there is no reliability -- because we actually reduced the transfer capability to a lower level. And are we really doing that as the proxy to the fact that we are not scheduling correctly. And if you reduce transfer capability, then your LMP scheduling system would say, you know, I need more generation on this site, and that's where I need the reactive. So, I'm sort of guiding it in the right direction.

The other way is, let's go back to the physical capability. As long as the resources on the other side, and then tomorrow the reactive and let the answer come out directly instead by proxy.

MR. O'NEILL: My understanding is this was a preliminary experiment for optimal scheduling reactive power in the NPCC region is dealing in just 400 million a year, which is probably not worth anybody expending any money on the practice.

MR. SASSON: I wonder if they took into account the fact New York reducing capabilities and then -- and whether that's really optimal.

MR. O'NEILL: They are working on it, and these were preliminary results that I have been privy too. As a matter of fact, they are sponsored by, I believe, the New England ISO.

MR. SASSON: No, actually, it's partially your guys on it.

MR. O'NEILL: 400 million a year could be actually invested.

MR. TERHUNE: Dick, suppose you look at this as plain vanilla transmission service request. Was the service never requested because the potential customers did recognize the opportunity? Or were there institutional obstacles to doing the work? Now, if the service is requested, the transmission owner, transmission provider have an obligation to act.

MR. O'NEILL: A lot of ways to study the problem of what they've got, if they have a rate freeze.

MR. ALVARDO: To follow up a little bit on this issue, the use of surrogate limit. The surrogate limit would probably get you to the right operating point, given the conditions. However, you may end up giving a very incorrect signal to the market, saying we need more generation here. When the right signal would be, we need just a little more rampant power here. So, be careful what you look it. You really do need to look at reactive power needs when you look. LMB alone will not tell you why you have a restriction, unless you do look at the reactive power.

MR. O'NEILL: I'm all for it.

MR. SHARMA: Question to Mr. Clarke. This Crosstown Cable, you have this terminal that you're about. Are you talking about the harmonic filters?

MR. CLARKE: The Crosstown Cable has the ITBP based, the insulated gate to bipolar -- it's --

MR. SHARMA: What they have is their -- and generate harmonics. Then you have inductors, capacitors to take care of the harmonics. I think that's what you are talking about. Am I correct?

MR. CLARKE: What we are talking about is the ability of the capability. Jose can probably describe it better than I can. But we're really talking about the ability of the equipment to generate or consume VARs.

MR. SHARMA: Are these the filters that you're talking about?

MR. CLARKE: No.

MR. ROTGER: The Crosstown Cable is a voltage (unintelligible). It relies on IGBTs for the insulated gate bipolar transistors to do the conversion to AC -- AC to DC and DC and back.

MR. SHARMA: Right.

MR. ROTGER: So, there are harmonic filters associated with the system.

MR. CLARKE: And functions like a DVAR basically.

MR. SHARMA: What I'm getting at, the VARS, they come from the inductors and capacitors, that basically take out the fifth and seventh of the harmonics. And it is a part of the entire cable network. In other words, if you didn't have the inductors, you could not transmit DC. So, what I'm trying to find out is, the VAR compensation that you're asking, what is it for? I'm not clear.

MR. CLARKE: Generally, the Crosstown Cable's capability and in this case it has a net capability at the terminal. When it is running full capability, when it is running full flow, it has the ability to run either lagging or leading, and that number is plus or minus 87 MVARs. I think that is the number.

When it is running at zero flow, as long the equipment is energized on either end, it can run at plus or minus 150 MVARs. So, it has net capability. With this technology, the power control technology that it has, what it does is, it creates a waive form. I'm a little bit out of depth here.

MR. O'NEILL: We have somebody that looks like they are willing to answer the question.

MR. CLARKE: It creates a waive form that is at the appropriate phase angle with respect to the voltage and the current. And it does that through the transistor technology. That's about as far as my depth goes.

MR. SHARMA: The cable is operating at full capacity, then you need the capacitors and inductors to filter out the harmonics.

MR. CLARKE: The HEDC light technology is different than the old HEDC technology. So there is a difference in the manner in which this IDBT based technology works. It's kind of like a DVAR versus -- if someone else can help me out here, I would really appreciate it.

MR. ALVARDO: There is no fifth and seventh to worry about. This is not a thyristor technology. This is actually a high frequency sort of chopping of the wave that can almost have four quadrant technology and you can actually almost operate them independently of the --

MR. SHARMA: So where are the VARs coming from?

MR. ALVARADO: The VARs are coming from the firing angle of the voltage source converter. They are at the base angle of the current.

MR. CALVIOU: -- there's a line that is a combination, that takes care of the DC and power flow, and that StatCom, the voltage source, which takes care of the reactive power control, which means have (unintelligible) on the megawatt on the MVAR. So, what you get is more or less, both the generation -- so the best summary of it, is that you get a combination of StatCom and (unintelligible), it's only there to take care of the harmonics. It's a minor thing. It has nothing to do with providing the MVARs. It's only there to filter out the harmonics.

MR. ZADLO: Thanks for the help.

MR. KELLY: I'd like to ask a question. In listening to this panel talk, I thought I heard a lot of agreement on two things. There should be capacity payments and they should be cost based. I'm not sure everybody addressed that. But it left with question marks on how you implement that. I wasn't sure if you were saying all generators should be required to have reactive power capability, and should receive capacity payments. Or only those generators that chose to have reactive power capability should receive capacity payments. Or only those generators who locate in an area where the transmission operator needs reactive power and include them in reactive power plan should receive reactive power payments, whether or not they have the capability. There are some other questions but that may be complex enough to start. And I hate to have the whole panel address it, but if some people have any strong views on that, please speak up.

MR. CALVIOU: I think my idea on this, Kevin, is that all generators should have some base level of capability, .95 to .95 capability, maybe they spoke of system upgrade to find a different level of capability. I we're looking for further capability beyond that, then I think you can have more discretion and the --

MR. KELLY: Pause on that point, if you would. Does that mean having that basic capability is a cost of entering the business, and you're compensated for it? You're only compensated if you're able to go outside the basic capability. Or are you saying you should have this basic capability and you should be compensated through capacity payments?

MR. CALVIOU: I think it's a requirement to entering the business, but I think you should be compensated through capacity payments, because I think that is the right incentive in terms of maintaining that capability. And therefore, my concern would be -- you could make it a cost of entering the business. You could, for example, in an RTO region say, you'll get paid by your capacity payments. But I think the issue there is, you're not being directly paid for it, and then you don't have any direct financial compensation associated capability. So, when, for example, you actually need to spend some money on the machine to maintain the capability, you'll not actually seeing a direct reward.

I think you could do it the other way, but I think you would attract more if you paid direct compensation.

MR. KELLY: Just to follow-up on that point. Others may have different view, but we have many generators and transmission providers at the table, and Mr. Mosher is still in the audience, he is representing customers. He might say, well, my customers don't want to pay for every generator having that capability. I think many times these some -- generators need to get compensated doesn't satisfy my need to service at the lowest cost. Do you have a response to that, Mayer?

MR. SASSON: When I spoke I started to plan the system either five to ten years at a time, and it's at that moment that you would address, are we really deficient. So, we are dealing that we have enough resources that problem would have come up with a deficiency much earlier. And once you are there, then the question is, do you want to pay all the sources? We advocate that you do, for all the reasons that Mike was saying, you must provide and encourage people to continue to maintain --

MR. KELLY: Excuse me for interrupting. I don't take that as a given. If you are saying that we have done the planning five years ago, we have enough capability now, then you are talking about pricing for short term dispatch of existing capability.

MR. SASSON: Yes.

MR. KELLY: But if you have pricing rules that either incent or dis-incent future investment, you may not be able to fulfill your plan of a market environment. So, I don't take that as a given. I think that's one of the most important subjects that we're here to address.

MR. SASSON: Okay. I don't disagree in the sense that you're mentioning it. The pricing is essentials for generation to site correctly. In fact, it may be that in areas where there is no transparent pricing rules, where you may have situations where there are areas where there is very little reactive, and areas that have too much reactive.

MR. KELLY: That takes me back to the question that I addressed to all of you. Should all generators automatically have to meet certain base capability, yes or no? And regardless of the answer, if the generator needs it, whether it has to or not, should it be paid, whether provider needs it or not; or only if the transmission provider needs it?

MR. CALVIOU: The answer, I think, Kevin, this is a long term business decision you make, when a generator is going to live with you for a long time. So, you know, I think you could envision a situation where our system operator or RTO looks at the system and says we're flush with reactive. We don't need .95 to .95 capability. That would relax the requirements so you just need .98 to .98 or something like that, and therefore, we're only going to pay for that. And maybe that will work for the next five to ten years. My concern would be, yeah, but twenty years time, you maybe dug yourself a good hole, and you're then going to have to buy your way out and it's a rather more expensive situation.

Now, I'm you could do a long term optimization to find the answer. I feel that a pragmatic, certainly in the markets that I've experienced, a pragmatic based requirement, like to .95 to .95, is not going to be wasted. You are going to get useful capability that's going to be able to mean over the life of the system you're going to be able to optimize the system.

MR. KELLY: Before I give others the chance to comment. I can't help but say, it's too bad we didn't have some people from the morning panel, because Mr. Mosher from APPA and Mr. Lucas from Southern Company agreed that they only wanted as much as the system needed and no more. Those two don't agree all that often, and it impresses me when they do.

MR. O'NEILL: Before all start singing the praises of this long term issue, I refer you to page 36 where we're plopping in a truck-mounted reactive power device, I'm not sure this device needs a long term payment. And it can be up and gone in a year. So, the idea of having these things as the long term investment, 20/30 year investment. This is an investment that's maybe only good for six months.

And you know, we're throwing around this wonderful thing, saying costs for -- that's a -- but I'm sure exactly what it is. We just heard guy from AEP this morning, condemn the AEP formula. But now we're all hopped up on cost reflective payments. What are the cost reflective payments that we're going to make?

MR. ZADLO: I just want to make a couple of clarifications, Kevin. First of all, generators, we don't necessarily choose our reactive power capability. Those requirements are imposed on us by the transmission provider. So to get to the bottom of this, it's at the time of interconnection that a decision is being made by the transmission provider as far as how much reactive capability needs to be installed. Okay. And it's at that point that when we go forward, the generator is incurring a capital expenditure for that.

Now, it's much more than just pulling out a generator that's capable of .85 or .9. There's a lot of design decisions that go into it as well. You may have to purchase low impedance transformers. You may have to design your auxiliaries in such a way such that at the high side you're able to deliver either the .95 or the .9, it varies regionally. So, I think it's important to remember that decision is being performed at the interconnection stage. And it's being imposed on the generator by the transmission provider.

MR. RUSNOV: Am I permitted to --

MR. O'NEILL: Go right ahead.

MR. RUSNOV: -- from this side of the fence for a moment.

MR. O'NEILL: You can make a speech from either side.

MR. RUSNOV: I come from a system planning background. I spent over 25 years planning Ontario's bulk power transmission system. We have been faced with exactly this kind of argument. There's always been a tug of war between the planners and the operators. Planners, by definition are cheapskates. They want to build the most economical, cheapest system they can. The operators know this is going to create some difficulties, and obviously, want more bells and whistles.

So, we have to cut this pie and come to some agreement on where we are going to set the requirements. I've been engaged the act of gaining approvals for major transmission lines in Ontario for decades. Not the last six years, I've been going for the last six years. And we know that the most difficult job in planning is to get approval for new transmission lines. We also know that regardless rate of growth; it is going to continue to grow. In Ontario now it's about one and a-half percent, one percent, one and a-half percent on a 25,000 megawatts system that's not insignificant. You come down to the point that you know that your transmission system is going to become increasingly more heavily loaded as time goes on, until you are almost at the breaking point, before you are going to be permitted to build another line. The more heavily your lines get loaded, the more reactive support -- I shouldn't use that term, because that's putting the cart before the horse. The more voltage support you're going to require in order to maintain system reliability.

So, what we did was, we specified every generator on the system, every major generator on the system is required to have a design which is .9 lagging and .95 leading power factor. It may not be needed immediately, it may not be needed in each location, one thing we couldn't predict is exactly how the growth in the system is going to evolve over the next ten or twenty years, so we imposed that requirement. And the system was designed with that in mind.

MR. MCCLELLAND: Was that an entry cost, or was that compensated?

MR. RUSNOV: Well, you see, Ontario Hydro was government owned utility.

(Laughter)

MR. RUSNOV: So, the customer, which I think an earlier panel said the customer ultimately pays for it. It's a matter of how you allocate it, and how it gets down to the customer. So I've got difficulties in some of the compensation issues. In Ontario we don't pay generators for the VARs they produce within that range. They are paid for their incremental costs, and those are losses. If they are requirement to go outside the specified range, they're paid extra. In fact, they're paid ten percent more on the market clearing price, as well as other costs that they incur. But they are basically the cost that they incur incrementally to provide the VARs, but not for the hundreds of MVARs between the .9 and .95 range.

MR. MCCLELLAND: I was going to ask, from an engineering perspective, engineers like to build safety. We like to build safety margins into our equations and into projects. From an economics perspective, it's not the most cost effective. I guess, back to your point, on the relative costs associated with that safety margin, it's relatively small. The projected life of generators and we've heard earlier speakers say, 25, 35, 40 plus years. Since you don't know what the system will look like, you don't know the system loads, and we don't the system configuration in the future. You can take your best shot at it, you typically build safety margins into the equipment. In addition, we know that projected retirements within the urban areas. We've seen that trend. So, generation that's constructed, especially generation within urban area are most likely to be called upon for dynamic reactive support.

We also know that load doesn't typically disappear. All of those reasons point to the safety margin that you refer to, Tom, within the generators themselves. But I would also like to go back to something a little earlier that Fernando had said. Fernando, and I'm sorry I didn't catch all of your remarks, but I caught most. And I know that you were talking about no differentiation between reactive power supplies. In other words, equipment. But one thing that I ask is that -- and I don't think you intended to go to that level, but there are efficiencies associated with handling, first, the distribution system, then the static transmission device, and then the dynamic reactive devices on the transmission system themselves. And then there are differentiations between the dynamic devices.

So, Fernando, would you say that good planning should include assessing the needs of those various level firsts; and then most effectively and efficiently applying reactive power mitigation to those areas, before you move on to determine what the dynamic reactive needs might be?

MR. ALVARDO: Yes. In my comment I was going to actually -- prior to answering that question of the order in which you want to determine things, my comment was going to be to address the question of pay as needed first, which is basically if you work to answer the question, yes, pay as needed, and then discover that you will, in fact, need a lot of it, particularly, if you realize the risk of not having far exceeds the risk of having it. If you put asymmetry in the necessity of the risk you're going to discover that it only makes sense. Now, if you want to complicate matters, one of the points I first said, is that there's a great simplifying of capability to make the problem no more complicated than it needs to be by requiring a certain. It's a surrogate, yes, but it's a good surrogate.

In terms of the order in which you address the issues, yes, indeed, you start with the simplest, most efficient thing at the distribution level. You get that solved first, then you work to the next level, which is some of the more static devices, then you find the needs. Final point, the reason a lot of the reactive at the generators is needed is not just for the value of queue, but the value, and I'm going to go back to something, the voltage control capability. If you are generating and your output is changed, you're going to have to have a means of controlling your voltage. So you are going to need some reactive no matter what. Even nobody tells you that you need some. So, just in order -- induction generators are a classic example of what happens when you don't, you really can't run them very well, can you?

MR. KELLY: I can't help it but, a quick retort. It's cheaper to have it, than the cost of not having it. We could debate the same argument for real power reserve margins, and that argues that having a substantial reserve is important. But at some point when it gets up to 55 percent, your 56 percent outweighs the benefit.

(Laughter)

MR. KELLY: And I don't have a good enough sense of typical power system's reactive power needs to know if paying reactive power compensation for 100 small generator in a exporting area makes good sense from a consumer's point of view.

MR. ALVARDO: Again, it really would have to be answered on a case by case. But the default ought to be -- one thing is, the risk of having a energy generator that exceeds and has a certain amount of reserves, which you are dealing with apples and apples. But once you have apples and oranges, you realize one MVAR under conditions of constraint can actually have the value of 20, 30 and 50 megawatts capability, you're dealing with a small amount of money that the amplification factor is so large that it doesn't make sense to even talk about it.

Sorry.

MR. O'NEILL: Ms. Ivey, did you have something to say?

MS. IVEY: Yes. First off I think -- I believe that any contractual agreements that already exist should be honored. But beyond that, when you're looking on a prospective basis, we should be using the planning process to determine what is required, and I would -- as someone who is paying these contracts, just disagree with some of the folks, as far as, we should pay for whatever generator hooks to the system. I think as a matter of practicality, any generator that hooks is going to, as folks have stated need to maintain some capability anyway, just for their own ability to remain synchronized to the system.

Once you get beyond that, the planning process should look at what are competitive alternatives that meet the reactive requirements. I don't think consumers should be paying for a generator that could go through its whole lifecycle and never be needed, much like you're saying, 100 generators in an exporting area where the load doesn't meet that requirement. So, yeah, I do believe there's a point where it should be competitive and we shouldn't necessarily be paying for --

MR. KUECK: But we don't do that for the vertically integrated utility generators. You want to impose that standard on -- but we don't do that for vertically integrated utility generators.

MS. IVEY: I think I'm speaking primarily within the concept of an RTO. I don't have an answer for you on the vertically integrated utility. But nonetheless, it should competitive once you are looking into a prospective basis.

MR. KUECK: Okay. I just have a quick one to follow up with what Fernando just said, that the problem should first be solved at the distribution level. And another thing that was said earlier, was that when we look at a long term solution where we have software available that can do a real-time locational market, that might be five or ten years down the road. I don't know, I've heard various estimates today. But it's down the road.

Would it be appropriate to put efforts toward some sort of an interim solution, short term solution that works at the distribution level? And then maybe parallel or later do the -- develop the market for a real-time locational reactive -- reactive pricing?

MR. ALVARADO: My understanding of the distribution solution problem is a jurisdictional issue, not a technical issue.

MR. O'NEILL: Thank you, Fernando.

MR. ALVARADO: If we could --

(Laughter)

MR. ALVARADO: -- I'm sure if FERC could have done it they would have already solved the problem on the local level. So, the problem is how do you address that? And the answer is, I don't know.

(Laughter)

MR. ALVARDO: I just tell you how to best solve it. In terms of the -- can we have an interim solution before -- I used to think that we had the problems solved that we could solve any problem, no matter how big, and get the optimum. Well, reality is a little different. It's a little more complicated. The best way is think of an evolutionary approach where you're going to improve the software gradually, and little by little come up with things that work better.

But don't take a plunge in relying on a non-existent technology to put up something out there that is going to need it, if it's going to work.

I don't know exactly what evolutionary steps are, but I would be cautious, but I definitely would move in that direction, yes.

MR. CALVIOU: A few people have said, I think we need to be careful that we're not too simplistic with saying, let's solve this at distribution level, everything else will look after itself. You can have a system where your distribution networks are perfectly balanced, reactive, unity power factors, large flows going over the transmission system and the problem is on the transmission system, because there's large and large reactive losses, and they need to be compensated for that.

I think there is an angle that we need to think about in terms of distribution systems and providing incentives. I that is a fairly large crack, actually. In the UK we have never been able to quite get the right incentives for end customers and distribution systems. And I'm sure there is a solution out there, but I haven't seen what it is yet.

I think in terms of the locational market, again, you have to just think, most markets are made up of buyers and seller. Well, the biggest player in the market is the transmission system. That is the biggest player. About 78 percent of the market will actually be the reactive going to the boxes, the lines, cables, transformers, and transmission system. I think that is why the market -- while it isn't the most traditional market, where you actually have buyers at one end, and sellers at the other end.

MR. O'NEILL: Let's go to the audience. Steve.

MR. LEE: Stephen Lee. I picked up on something that I mentioned earlier this morning. I think it's the right direction. I wanted to explore it a little bit further and answer the one question you had. Your concern about opening up the reactive power, I don't think that is necessary. If you really look at the (unintelligible). The cost function, the rate function is the cause of the fuel and et cetera -- of running a generator upward. It's a function of (unintelligible). So the costs -- voltage limits as an additional constraint on it. And also impose the idea of New York Power, New York ISO, reactive zones. You have reactive consumption is then balanced within reactive zone. You ensure additional physical feasibility in the problem. And what you will find out is that you can come to essentially the costs adjusting your reactive power upward and (unintelligible) changes et cetera, all these voltage control parameters in such a way to satisfy all those constraints. But what is happening, of course, is that there will be re-dispatched costs. Cost function goes up, right? Then directly to the voltage costs, due to the necessary conditions to make those adjustments. There is no double counting, no double counting costs. You can calculate the market price for service additional incremental megawatt load in a zone. You also have an additional costs of serving incremental MVAR load in each zone. There is not double counting the costs. There's no need to do a reactive power market bidding processing. Things are simply calculated as a matter of settlement. So, you can design a settlement system to calculate this, and it will be supplied very accurately. That incremental cost of adjusting voltage for each zone will positive or negative. So, in addition to cost it could compensation of transmission owner may have to come up sufficient money. All this translates back to the customer costs.

You can calculate the proper cost of customers who have higher reactive demand and those that less reactive demand, there is no additional revenue corrected. There is no double counting money, but there is a proper price signal given to customer, given to suppliers of equipment to put in the money, to put investment where it can actually be to market benefit.

MR. O'NEILL: Can I ask the group, is there any dissenting voices into moving towards more efficient dispatch and more efficient inclusion of reactive power in the dispatch? Dissenting voice to more efficient dispatch?

MR. TERHUNE: I agree with Steve that the dispatch of reactive resources is an appropriate element of a security constrained locational marginal pricing dispatch. I don't disagree with that at all. I think it does add a fair degree of complexity to the issue. University has proven that it's feasible. So, there's not a conceptual technical challenge.

Of course, back home in my country, I'll be very happy to get through April 1st very slowly and calmly to an adequate degree of complexity to start with, and waive a farewell before introducing another substantial load. But I do agree that it belongs there. And even without sophisticated computer programs, the job of the day to day operating dispatcher is to use his intelligence and experience, and his operating tools to do on a practical basis the very same things. To manage the system in the most efficient manner that that operator can.

MR. O'NEILL: Well, we'll get Andy to work on the problem while you --

(Laughter)

MR. LEE: I want to just finish up on my comments. I agree rushing limitation is dangerous. But certainly I think -- we talk about incremental. I'd like to talk about resolution and changes in methodology in software. Indeed, it is needed to carry forward. And I think it is better to take a --

MR. O'NEILL: Who are you with, again?

(Laughter)

MR. LEE: -- if I may, two weeks from now, March 22nd we are going to have a (coughing) on reactive power management at the Washington DC office. Thank you.

MR. SASSON: I often think a system planner that studies the system five/ten years into the future, will always assume that all facilities in the grid are available. We do that in the operations. We schedule systems, rightfully so, in terms of the most efficient schedule. And many generators are not needed in a given hour, they are not going to be scheduled on. It would inefficient to do so. And so while a planer may think the system is okay. The operation does not consider reactive in its scheduling. We should not be surprised that the end result may not be as good as we would like it to be, because it wasn't even considered. It was not in our objectives. I think that is what Steve Lee was trying to say. Thank you.

MR. LIVELY: My name is Mark Lively. I'm a consultant utility economic engineer. Sixteen years ago I wrote an article, published in Equipment Utilities (unintelligible), saying that we needed to pay for unscheduled flows of electricity. When Fernando sent me a comment that he was going to speak here, he and I are both on the Energy Policy Committee together, I said, you need to say that we need to price unscheduled flows of electricity. I got an e-mail back from Mayer, who is also on the committee. And Mayer said, yeah, let's schedule it. Let's schedule reactive power. And we heard a few people say today, what we scheduled is not reactive power. We schedule voltage. Well, if we look at voltage, some people might call it a public good. It is certainly not commodity. We can price reactive power as a commodity. And we can price reactive power against that voltage schedule to achieve that voltage schedule. We've also talked earlier today about, well, where should we start the reactive power planning. People said, well, it's not on the distribution grid. I don't want to talk about the planning there. But let's start using that as an example of scheduled reactive power and pricing that scheduled reactive power. The schedule reactive power onto the distribution grip should be close to zero. To the extent that it varies from that zero, you need to price it. If the voltage is where it is supposed to be, then that reactive power is like what they used to say about nuclear power, it's too cheap to meter. If voltage is at variance from where it is supposed to be, then we need to set substantial pricing for that reactive power that is going into the distribution grid. So, how does that then handle the issue of pricing reactive power out of IPPs, out of generators, out of reactive devices of whatever we want to talk about on the transmission grid? Well, there may be a requirement, to get like in Canada, that Mr. Rusnov said, that they have a requirement of plus or minus 90 percent. And that anything within that plus or minus 90 percent is not paid for. Where if you don't go to plus or minus 90 percent in voltages off nominal, then you have to pay a penalty for whatever reactive power that you don't -- that you have failed to produce that would have put you at that 90 percent. Then you need to have a payment to the generator when he goes beyond that 90 percent limit, and is trying to move the voltage in the right direction.

As I said, we need to have a way to price that unscheduled flows of electricity. About the same time that I wrote my paper, there was a movie that came out. It was called Field of Dreams. In the movie the Field of Dreams there's a saying, you build it, they will come. Well, at the end of the movie he built the ballpark, and you saw a whole stream cars coming. Well, I think if we price reactive power correctly that we're going to get a whole stream of little reactive power producers, whether it's small distributed generators, whether it's larger generators, IPPs on the network, whether it's the people from American Semiconductor, or other people who put FACTS devices. But if we have a way to price the unscheduled flows of electricity, then we are going to get the right reactive power. Thank you.

MR. O'NEILL: It's 4:00. So, let me try to sum up. First of all, we're open for comments. I don't remember, that deadline sometime in April. Does anybody remember exactly when? You can look at our page on the Web. Obviously, one of the questions, we'd like to get answer, where do we go from here. We'd like your comments on the need for better measurement, the need for better reliability planning, reliability audits. We heard a lot about testing for reactive power capability, and certainly we'd like to understand more about how you would design that testing.

We heard a lot about cost-based payments for capacity. We lost AEP as an advocate of the AEP Method. So, we're looking for new methods to price the cost-based capabilities. And we'd like you to think about technology neutral issues. How merchants can play in this market, when for whatever reasons the problems aren't being resolved by the existing system. And if there is anything you want to add, I am for it.

Fernando, go right ahead.

MR. ALVARDO: Nobody mentioned the reduction in the -- the technology that may reduce the reactive lines that may reduce the requirements for reactive power. Let's not throw that one out.

MR. O'NEILL: If you price it right you will get the lines.

MR. ALVARDO: Yeah, but you've got to price the lines too.

MR. O'NEILL: Yeah. If you price reactive power right you get the pricing on the lines. I'd like thank everybody for coming. I'd like to encourage people to submit comments. And you'll hear from us in the future about what we're doing.

(Whereupon, the conference in the above-entitled matter was concluded.)

CERTIFICATE OF REPORTER

I, Pamela S. Jenkins, do hereby certify that I took the audiographic notes of the foregoing proceedings and the same were reduced to transcript under my direction; that the foregoing is a true record of said proceedings; that I am neither related to nor employed by any of the parties to the action herein; and, further, that I am not a relative or employee of any attorney or counsel employed by the parties hereto, nor am I financially or otherwise interested in the action.

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